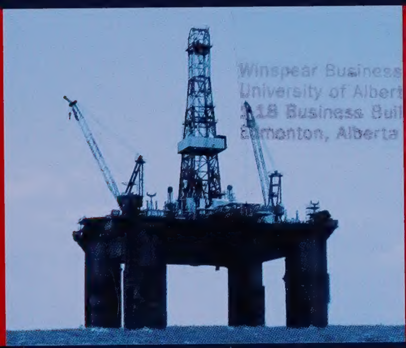

our future growth defined

CANADIAN NATURAL RESOURCES LIMITED
ANNUAL REPORT 2001

owner operator

core area focus

balanced assets

project inventory

capital discipline

team commitment

environmental responsibility

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defined

Canadian Natural is one of the largest independent oil and natural gas producers in Canada. We achieved this status through our defined growth strategy. Our diversified combination of assets in western Canada, the North Sea, and offshore West Africa enables us to perform in any economic environment. We produce a balanced mix of natural gas, light oil and heavy oil, and are planning a major oil sands mining development.

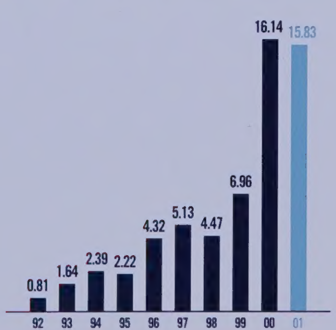
financial **highlights**

	2001	2000	1999
FINANCIAL			
($ millions, except per share data)			
Gross revenue	$ 3,561.4	$ 3,222.5	$ 1,286.8
Cash flow from operations attributable to common shareholders[1]	1,920.0	1,883.6	723.5
Per share – basic	15.83	16.14	6.96
– diluted	15.25	15.64	6.85
Net earnings attributable to common shareholders[1]	698.2	782.2	200.2
Per share – basic	5.76	6.70	1.93
– diluted	5.56	6.50	1.90
Net capital expenditures	1,884.5	1,136.0	1,900.6
Acquisition of Ranger Oil Limited	–	1,687.3	–
Long-term debt	2,669.2	2,454.5	2,156.8
Shareholders' equity	3,868.9	3,216.9	1,892.0

[1] *After dividend on preferred securities.*

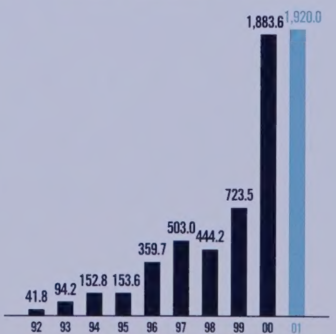
	2001	2000	1999
OPERATING			
Daily Production Before Royalties			
Crude oil and NGLs *(mbbls/d)*			
North America	167	155	87
North Sea	36	17	–
Offshore West Africa	3	2	–
	206	174	87
Natural gas *(mmcf/d)*			
North America	906	793	721
North Sea	12	1	–
	918	794	721
Barrels of oil equivalent *(6:1, mboe/d)*	359	306	207
Average Prices Before Royalties			
Crude oil and NGLs *($/bbl)*			
North America	$ 21.00	$ 28.15	$ 21.04
North Sea	38.66	44.61	–
Offshore West Africa	33.57	45.77	–
Company average	24.31	29.99	21.04
Natural gas *($/mcf)*			
North America	5.19	4.53	2.36
North Sea	2.51	3.66	–
Company average	5.16	4.53	2.36
Drilling Activity *(net wells)*			
North America	1,087	812	727
North Sea	3	1	–
Offshore West Africa	2	–	–
	1,092	813	727
Core Undeveloped Land Holdings *(thousands of net acres)*			
North America	6,491	6,276	4,849
North Sea	237	211	–
Offshore West Africa	1,194	1,528	–
	7,822	8,015	4,849

Cash flow from operations per share attributable to common shareholders* ($)

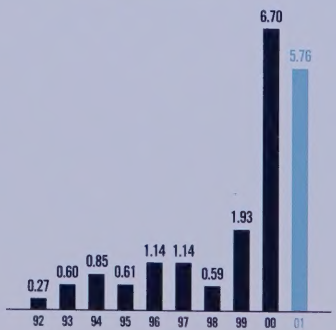


**Restated to reflect two for one split in June 1993.*

Cash flow from operations attributable to common shareholders ($ millions)



Net earnings per share attributable to common shareholders* ($)

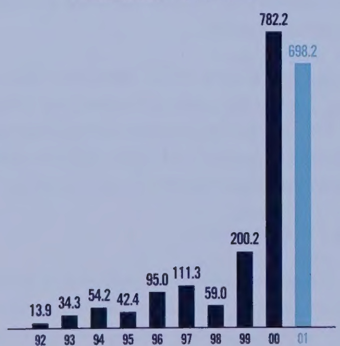


**Restated to reflect two for one split in June 1993.*

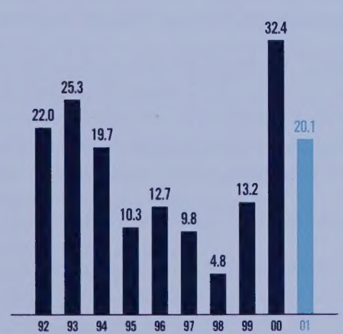
Our financial performance is strong because we are a low cost producer – a core competency we consider to be a sound asset. This enables us to deliver value and realize the cash flow necessary to keep our company in a solid financial position even in volatile market conditions.

	2001	2000	1999
Reserves Before Royalties			
Crude oil and NGLs *(mmbbls)*			
Proved			
North America	644	642	554
North Sea	85	102	–
Offshore West Africa	61	37	–
	790	781	554
Probable			
North America	95	88	86
North Sea	23	33	–
Offshore West Africa	51	9	–
	169	130	86
Total	959	911	640
Natural gas *(bcf)*			
Proved			
North America	2,566	2,360	2,183
North Sea	94	91	–
Offshore West Africa	69	66	–
	2,729	2,517	2,183
Probable			
North America	349	402	364
North Sea	24	23	–
Offshore West Africa	27	19	–
	400	444	364
Total	3,129	2,961	2,547
Barrels of oil equivalent *(6:1, mmboe)*			
Proved	1,245	1,201	918
Probable	236	204	147
	1,481	1,405	1,065

Net earnings attributable to common shareholders ($ millions)

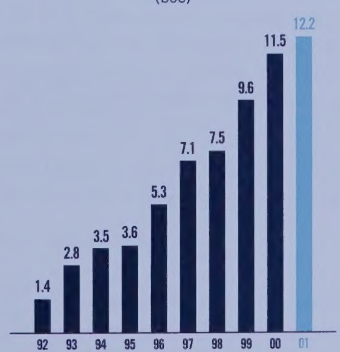


Return on average common shareholders' equity* (%)



Includes preferred securities as debt equivalents.

Reserves per share* (boe)



Restated to reflect two for one split in June 1993.


Allan Markin Tim McKay Réal Cusson Brian Illing Doug Proll

letter to shareholders

The year 2001 was a year of strengthening our position as a product-diversified exploration and development company. Assets in our core areas are well positioned with defined growth strategies in place for natural gas, crude oil and synthetic light oil. Our year-over-year natural gas exit volumes increased by 30% for 2001. We continued to develop our international portfolio of light oil assets and we made significant strides in making our Horizon Oil Sands Project become a reality.

Company management believes that a balanced asset base provides less risk when compared to an overweight exposure to a sole commodity. It is the strength of our asset base and the Company's adherence to our defined and disciplined long-term growth strategy which together provide opportunities for profitable growth.

FINANCIAL AND OPERATING HIGHLIGHTS

During 2001, Canadian Natural's production increased by 17% to over 359 thousand barrels of oil equivalent from 306 thousand barrels of oil equivalent in 2000. Strong commodity prices enabled the Company to generate over $1.9 billion ($15.83 per share) in cash flow from operations and $698 million ($5.76 per share) in net earnings. Comparatively higher oil prices in 2000 resulted in cash flow of $1.9 billion ($16.14 per share) and net earnings of $782 million ($6.70 per share).

During 2001, Canadian Natural proactively managed its exceptional natural gas asset base to take advantage of high prices during the first quarter. Through its four core natural gas areas the Company increased its exit rate production by 450 million cubic feet per day, after adjusting for average declines of 25% on existing production. These additions were accomplished through acquisitions and the drilling of 476 natural gas wells, including 150 million cubic feet per day of exit production from the Ladyfern prospect. As a result of this activity, average natural gas volumes throughout the year were 16% higher than those achieved in 2000 and natural gas now represents 48% of the Company's production mix.

Average daily crude oil and natural gas liquids production increased by 19% over 2000, largely the result of the full year impact of the mid-2000 Ranger Oil Limited ("Ranger") acquisition. Due to unusually high heavy oil price differentials, the Company drilled fewer heavy oil wells than in previous years and during December actually reduced output from certain properties. This proactive deferral of production had the desired impact and heavy oil price differentials in early 2002 are much lower than those experienced throughout 2001.

During the year, we also made significant progress on our longer-term projects:

- In Northeast British Columbia we continue to identify new natural gas exploration opportunities on our existing landbase using the technologies and data that we have gathered from our centrepiece Ladyfern asset. Through this exploration effort we expect to be able to offset Ladyfern declines in 2003 and continue to grow our natural gas production in the future.

Steve Laut Lyle Stevens Allen Knight Réal Doucet John Langille

- In offshore Côte d'Ivoire, our development of the Espoir field was on time and on budget with light oil production to the floating production storage and offtake ("FPSO") vessel commencing in February 2002. This first leg of international success will be built upon in coming years with East Espoir field production reaching 30 thousand barrels of oil per day. Several other targets in the region will be drilled and developed, including the highly prospective Baobab field which was originally discovered during the first quarter of 2001.
- We achieved significant progress in our Horizon Oil Sands Project as we issued a public disclosure document and completed the first phase of front-end engineering work. The Company's approach for this project is to extensively evaluate new technology options and predesign the infrastructure prior to construction. In this way, Canadian Natural will increase cost certainty before significant activity begins. A strong staff of experts with significant experience in design, construction and operations in each of mining, extraction and upgrading has been assembled to lead this work. With the work completed to date, the project is looking more robust than anticipated and leads us to believe that this is likely the best undeveloped lease in the region.
- Canadian Natural increased its midstream asset base by purchasing the remaining 50% interest in the ECHO Pipeline and assuming operatorship. We also participated in the expansion of the Cold Lake Pipeline in which we hold a 15% working interest. The Company now controls the transportation of approximately 75% of its heavy oil production to the international mainline pipeline systems.

We operate under our defined strategies.

Year-end proved and probable reserves of crude oil and natural gas liquids and natural gas approached 1.5 billion barrels of oil equivalent, comprised of 959 million barrels of oil and natural gas liquids and 3.1 trillion cubic feet of natural gas. This represents a six percent increase in natural gas reserves and a five percent increase in oil reserves from the beginning of the year. The production life of these reserves is 11 years on a barrels of oil equivalent basis, with the natural gas reserve life at 9 years and oil reserve life at 13 years.

Proved reserves account for over 84% of the total reserves, with approximately 32% of these reserves not yet developed. The vast majority of proved undeveloped reserves are attributed to heavy oil reserves, reflecting the Company's large strategic base of heavy oil assets in western Canada. No reserves have been recorded for our 100% interest in the Horizon Oil Sands Project near Fort McMurray, Alberta. Our testing of these leases indicate that reserves of approximately 6 billion barrels of bitumen will be ultimately recoverable through surface mining and in-situ recovery schemes.

Proved and probable reserve additions equalled 1.6 times 2001 production (1.3 times using only proved reserves), at a finding, development and on-stream cost of $8.47 per barrel of oil equivalent ($9.97 per barrels of oil equivalent using only proved reserves).

CLEAR PATH TO PROFITABLE GROWTH

Our long-term strategy is based upon ensuring financial strength and operational flexibility. The central parameter of the growth strategy is to continue to build a diversified asset base which is balanced between natural gas, light oil and heavy oil. The plan further incorporates a balance between exploration and acquisitions with the cost effective exploitation of those assets. Our focus is on core areas where we understand the

Our mission statement brings our company together on a daily basis, in all facets of the workplace: "To develop people to work together to create value for the Company's shareholders by doing it right with fun and integrity."

limitations and extent of both the area and the product produced. We strive to maximize our working interests and operate all our drilling and production activities. This approach significantly increases flexibility and control over the timing and extent of our exploration and development plans as well as our operating costs.

Our strategy of maintaining financial strength and capital discipline was evident in 2001 as the Company continued to improve its financial ratios. Significantly, a highly successful inaugural 10-year debt offering in the United States was completed in July. The public debt offering enabled us to cancel three bank lines of credit aggregating approximately $1 billion. This was followed up with a 30-year offering that was completed in early 2002. Closing long-term debt reflected a 1.4x debt to cash flow ratio and a debt to book capitalization of 42.5%, well within the Company's guidelines for balance sheet management.

Canadian Natural also believes in being a meaningful participant in the communities in which we conduct our business. Over the past year, we conserved 29.5 million cubic feet per day of solution gas by decreasing flaring and venting of natural gas at our large-scale projects such as Pelican Lake and other oil properties. With respect to community responsibility, we initiated Petroleum Employment Training programs to provide industry employment opportunities for aboriginal people. We also made significant financial donations to the University of Alberta Faculty of Engineering and the Alberta Children's Hospital.

By working together, we are determined

OUTLOOK FOR 2002

As we look into 2002, we see further growth. Already this year we have achieved first oil at our international development in Côte d'Ivoire. The Espoir project was completed on time and on budget, and has initial production levels in excess of our original expectations. We will add to this international success with additional drilling in Côte d'Ivoire. At Baobab, our exploration well was followed by the drilling of a second successful well which tested at 10 thousand barrels of oil per day. Additionally, a new nearby prospect called Kossipo will be drilled in 2002.

In Canada, our natural gas success continues with new pipeline capacity from the Ladyfern region available in early March 2002 and five new Slave Point prospects being drilled in the Ladyfern region during the first quarter of 2002. At Pelican Lake, we will commence testing of our new emulsion flood that could add significantly to the total oil reserves recoverable from the pool. Government approvals for our Primrose thermal oil expansion are expected in 2002, following which we will convert to high pressure steam injection, yielding production increases over the next few years. On our world-class oil sands project, Horizon, we will initiate formal regulatory processes in the summer of 2002 with construction anticipated to commence in 2004.

Finally, our proactive curtailment of heavy oil production in 2001, including a reduction in the number of heavy oil wells drilled and a change in the steaming pattern at Primrose, has helped to narrow the heavy oil differential back to historical levels. We continue to monitor this market and continue to work on strategies to eliminate some of the uncertainty surrounding this commodity pricing.

Based upon a $1.5 billion dollar capital budget in 2002, the Company expects to produce an average of 379 thousand to 393 thousand barrels of oil equivalent per day, a seven percent increase over 2001

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core area focus
balanced assets
project inventory
capital discipline
team commitment
environmental responsibility

Everyday, our multi-disciplinary teams work together to find optimal business solutions.

levels. This increase is comprised of natural gas production increases to between 1,075 million and 1,125 million cubic feet per day (versus the average of 918 million cubic feet per day sold in 2001) and average oil and liquids sales to between 200 thousand and 210 thousand barrels per day (versus the average of 206 thousand barrels per day in 2001).

TEAM EFFORT

We have a proven track record of effective decision making, led by the synergies created through our broad based approach to corporate management. We believe every employee's opinion contributes value. Through a flat corporate structure we have created an infrastructure which facilitates communication of these opinions and suggestions to the Management Committee on a weekly basis. This Committee collectively represents the roles of Chief Executive Officer, Chief Financial Officer and Chief Operating Officer.

Teams within each business area provide first hand insight into the issues necessary to make good business decisions. These teams include members of various professions and expertise working together on various projects and regions.

This structure has proven effective in adding shareholder value and is consistent with our corporate mission statement: "To develop people to work together to create value for the Company's shareholders by doing it right with fun and integrity".

to achieve our full potential.

The entire management team is very excited about our future prospects, and we look forward to continuing to deliver top tier results to our shareholders. We would also like to thank our employees, whose hard work and dedication to our mission statement and company has propelled Canadian Natural to where we are today. Also, we appreciate the consistent and beneficial contribution of our Board of Directors and the continued support of our shareholders.

On behalf of the Board of Directors,

John G. Langille
President
March 18, 2002

Allan P. Markin
Chairman

Lonnie Abadier, Alnoor Abhvani, Cheryl Agnew, Sina Akinsanya, Brian Akre, Chris Alderson, Gregory Alexander, Sullivan Alexander, Elena Algazina, John Allen, Eva Almeida, Gordon Almond, Jocelyn Alonso, Nelson Alook, Cheryl Ambler, Bruce Anderson, Greg Anderson, John Anderson, Kelvin Anderson, Murray Anderson, Todd Andrews, Gloria Angeles, Sherley Angers, Kari-Lou Antolic, Rogerio Antonio, Kathy Antonishyn, Shelley Antonuk, Jim Archibald, Evalynn Arden, John Argan, Mark Ariss, James Arkley, Rob Armstrong, Jacqueline Asso, Sialla Assohou, Maguy Atheba, Alan Atkinson, Clifford Atkinson, John Atkinson, Jason Auch, Bernard Auger, Marvin Auger, Charles Badiou, Janice Baik, Michael Baik, Dwayne Bailer, Judy Bailey, Fatou Bakayoko, Chris Baker, Reginald Baldock, Vaughn Baldwin, Sheldon Ballas, Darwin Banash, Teresa Banny, Inge Bantli, Jack Bardahl, Garry Bardoel, Larry Bardoel, Nicole Bares, Suchada Barker, Carey Barnstable, Paul Barrett, Lisa Barrett, Marty Bartman, Colin Beaman, Aura Beattie, Laurier Beaunoyer, David Bechtel, Ewan Beenham, Robert Befus, Adrian Begley, Paul Beilby, Lesley Belcourt, David Bell, David P. Bell, Jon Bell, Reg Bellanger, Wes Bensmiller, James Bentley, Linda Bentley, Linda Beresh, David Berger, Doris Bergeron, Jeffrey Bergeson, Allan Bertram, David Biagi, Corey Bieber, Inge Biener, Linda Bigelow, Greg Bilcox, Rob Bilsland, Roger Bintz, Mark Bishop, Darwin Bittner, Kevin Bjornstad, Jennifer Black, Kenneth Blackhall, Barbara Blacklock, Kerri Blackmore, Melissa Blackwell, Deana Blais, David Blake, Shamane Blake, Shawna Blanchard, Christopher Blatchly, Dwayne Blenner-Hassett, Heather Bobbett, Dennis Boehmer, Darcy Boettger, Marty Boggust, Greg Bolin, Shawn Bond, Patricia Booklall, Jayne Booth, Albert Bordeleau, Kerrie Bordeleau, Suzanne Boudignon, Slade Bowers, Donna Bowles, Dale Boychuk, Jeffrey Boyd, Patrick Boyd, Aaron Boyer, Neil Bozak, John Brabec, Bryan Bradley, Marianne Brady, Mary Jane Brady, Eleanor Branagh, Myron Brataschuk, Brad Braun, Colin Brausen, Joseph Breland, Paul Breland, Barry Brick, Pedro Briguel, Ken Brinkac, Shawn Brockhoff, Steve Brown, Robert Brownless, Elizabeth Brownrigg, Gordon Bryant, Rick Buchanan, Chris Bulley, Clarence Bur, Trevor Burchenski, Keith Bureau, Grant Burgess, Jacquie Burke, Rick Burns, Sharon Burns, Leanne Butz, Tricia Butz, Shaun Byrne, James Cadrain, Richard Calliou, Ventura Cambundo, Lorraine Cameron, Tyson Cameron, Clayton Campbell, Dean Campbell, Doug Campbell, Robert Campbell, Andre Campeau, John Capstick, Fred Cardinal, Harley Cardinal, Sharon Cardinal, Wayne Cardinal, Jim Carey, Ian Carleton, Stephanie Carolan, Rick Carr, Gary Case, Trevor Cassidy, Neil Cathmoir, Mike Catley, Sandy Cavers, Dante Cay, Samuel Cervantes, Ozlem Cetin, Ernest Chachula, Jik Chan, Sarah Chan, Tim Chan, Alan Chaney, Todd Chapman, Darryl Charabin, Rachel Charman, Cynthia Chartrand, Stephen Chastell, Cindy Chauncey, Mike Chernichen, Jerry Chessell, William Chiverton, Jessica Choi, Raymond Chong, Wayne Chorney, Sherry Chow, Jeannie Choy, Alphonse Chretien, Steven Christie, Andy Chu, Heather Church, Kadia Cisse, Stella Clapham, William Clapperton, Andrea Clark, Mike Clark, Robert Clayson, Greg Clegg, Dale Coburn, Judith Cochran, Anna Cochrane, Jennifer Code, Sabrina Colangelo, Martin Cole, Elva Coley, Lilie Collins, Brad Cook, Kent Cooper, Gordon Cormack, Rosetta Cormier, James Corner, Neil Costeloe, Wayne Cote, Juan Cottier, Kathryn Courtney, Dave A. Cousins, David H. Cousins, Gordon Coveney, Keith Cowger, Jonathan Cox, Nigel Crabb, Harry Crabtree, Layne Craig, Bruce Crain, Beverley Creed, Roger Crichton, David Cridland, Christopher Cross, Lloyd Cross, Kirby Crowell, Reynaldo Cruz, Anthony Csabay, Corinna Culler, Arley Currie, Stuart Curtis, Kenneth Cusack, Pat Cusack, Réal Cusson, Ken Cyr, Andre Da Costa, Helder Da Silva, Layne Dalgetty-Rouse, Sandrine Dalo, Walter Danchak, Simon Daniel, Gene Danyluk, Lynne Darlington, Ivone Da Silva, Tim Davidson, Todd Davidson, Meaghan Davis, Randall Davis, Robert Davis, Stephen Davis, Leonard Dawe, Robert Day, Daphne De Groot, Eric De Kock, Claudia De La O, Lynne De Villenfagne, Harry Dean, Parry Debusschere, Raymond Dechaine, Roland Dechesne, Ian Degiano, Barbara Deglow, Bonnie Deis, Benita Delorenzo, Michael Delorme, Peter Dempsey, Edward Deren, Tom Dereniwski, Betty Der-Griffiths, Travis Desilets, Catherine Desjarlais, Michael Desroches, Laurie Devey, Dease Devine, Karen Deyaegher, Sonia Dhuga, Aldo Di Flumeri, Karim Mounian Diallo, Sumara Díaz, Sandy Diguer, Irene Dikau, Mike Dingley, Scott Dionne, Kathleen Dixon, Shawn Doble, John Dodman, Conrad Dombowsky, Kelly Dombrosky, Manuel Pedro Domingos, Denise Donald, Minh Dong, Veronica Dooling, Tim Dootka, James Doran, Sascha Dorer, Réal Doucet, Blair Dow, Dahl Dow, Angela Dowd, Bobby Dreger, Colleen Drury, John Drury, Steve Drysdall, Calvin Duane, Jon Dudley, Simon Dugdale, Albert Duhaime, Cheryl Dumais, John Dumais, Ron Dunbar, Sean Duncan, Jill Dunlop, Harvey Dutchak, Eugene Dyjur, Gary Earl, Kevin Earle, Suzanne Eaton, Greg Ecker, James Edens, Robert Edgar, Josephine Edoukou, John Elgar, Carole Eliuk, Anthony Ell, David Ellis, Jerry Enders, Rommel Engler, Joanne English, Quentin Enns, Terry Erickson, Sean Estell, Monique Evans, Tim Evans, Maureen Evers-Dakers, Mike Eynon, Mcgarry Eyre,

Our employees are key to our success.

Leonard Fabes, Heather Fahey, Catherine Falconer, Andy Fankhauser, Denise Farrell, Arthur Faucher, Karman Fayant, Brian Fehr, Ira Feland, Kurt Fenrich, Joaquim Fernandes, James Ferrier, Magdalena Ficek, Darren Fichter, Jerry Field, Michael Filipchuk, Calvin Fisher, Rod Fitzpatrick, Craig Flamand, Deborah Flanagan, Paul Flanders, Ken Fleck, Rodney Flett, Trevor Flood, Edmond Foisy, Hop Chi Fong, Gregory Fontaine, Robert Fontaine, Carri-Ann Foote, Adele Forcade, Curtis Formanek, Randy Formanek, Devon Fornwald, Peter Fowler, Donald Fox, Ron Frank, Jody Franz, Gail Fraser, Ken Frazer, Kelly Freed, Roger Frere, Brad Friesen, Kenneth Friesen, Kevin Frith, Frank Frosini, Karen Fujimoto, Ted Furuya, Josephine Gaddi, Leonard Gadowski, Sharon Gaehring, Kelly Gagne, Scott Gair, Larry Galea, Ron Gall, Michael Gallon, William Galloway, Yoko Galvin, Terry Gammel, Gerri Gaughan, Maurice Gauthier, Alain Gbo, Michael Geldert, William George, Michel Germain, Raymond Germain, Albert Gervais, Clark Getz, Helga Giles, Ralph Gill, Sharen Gillett, Doug Ginn, Ben Gisby, Marvin Gladue, Russell Gleed, Cody Goddard, David Golden, Susan Gole, Brian Gonsalves, Yvonne Gonzalez, Yvon Gosselin, Audrey Gothreau, Allan Gould, Antonella Goulet, Sandra Goundrey, Debra Graham, Jacqui Grant, David Gratton, Melinda Gravelle, David Gray, Ernie Greenwood, Derek Greidanus, Clint Greschner, Lesley Griffin-Beale, Neil Guay, Robert Gullion, Shane Gullion, Swarna Gunaratne, Carolyn Gunderson, Edward Gushnowski, Elaine Gussman, Graham Gustafson, Bartley Haahr, Violet Haddad, Jenise Hagel, Egbert Hagens, Sam Hajar, Shemin Haji, Dean Halewich, Rick Halkow, Robert Hallett, Tim Hamilton, Kevin Hamm, Michael Hammel, Rick Hammond, Dave Handy, James Hansen, Kent Hardisty, Ken Harke, Angela Harlos, Erik Haroldson, Bill Harris, David Harris, Jody Harris, Roger Harris, Lisa Hartman, James Harty, Mike Harty, Jerry Harvey, Wayne Hatton, Joey Hayward, David Haywood, Jay Heagy, Larry Heath, Terry Heck, Steve Hedley, Ken Hedstrom, Judy Henderson, Mark Hendricks, Anita Hennig, Judith Hermann, Michele Herron, Dan Hiebert, Matthew Higgins, Gordon Hill, Steve Hill, Laureen Hillebrand, Jocelyn Hillier, James Hinde, Barbara Hofer, Kevin Hogg, Chris Hojnik, Andrew Holding, Tony Holland, Ian Holmes, David Holt, Shannon Hood, Hans Hoogendam, Loreena Hopkins, Bill Horne, Keith Hornseth, Joanne Huang, Mark Hughes, Terry Humbke, Robert Hunter, Dean Hutchinson, Ray Hutscal, Bruce Hutt, Donald Huxley, Matthew Ilchuk, Brian Illing, Michael Ingles, Brad Inman, Anne Irving, Karen Ivan, Judy Jackson, Kevin Jackson, Rob Jackson, Ken Jacobs, Ken Jacobson, Irene Jacula, Todd Jacula, Chris James, Maria Jancewicz, Leonard Janzen, Calvin Jarratt, Brent Jensen, Kevin Jensen, Parry Jensen, Qi Jiang, Agostinho Joao, Terry Jocksch, David Johnson, Evan Johnson, Greg Johnson, Jeffrey Johnson, Stacy Johnson, Stephen Johnson, Victoria Jolliffe, Delbert Jones, Mark Jones, Damian Jordan, James Jung, Dale Kachowski, Asif Kachra, Carol Kadutski, Raymond Kahanyshyn, Harwinder Kang, Nashila Kanji, Brad Karaja, Alice Karg, Lori Karpinka, Angela Karst, Doug Kary, Lynn Kasper, Shelina Kassam, Myles Kathan, Deanne Katnick, Christopher Kean, Philip Keele, John Kellie, Jeff Kemp, Wayne Kennedy, Blair Kessler, Kimberly Kielt, Richard King, Stacey King, Linda Kinney, Marvin Kinsman, Patrick Kirrane, Brent Kissel, Mario Kiteculo, Cody Klatt, Allen Knight, Barney Kobzey, Gaba Eliane Kodjo, Kouakou Koffi, Kari Kohalmi, Danell Kokol, Eva Komers, Ibrahima Kone, Diane Kostiuk, Ann Kostyshyn, Richard Kowalski, Kevin Kowbel, Cameron Kramer, Trevor Krause, Todd Kreics, Jeffrey Kreiser, Patti Krekoski, Peter Krol, Gary Krushell, Gabriel Krywolt, Chris Kubisch, Micheal Kunert, Len Kurowski, Frank Kurucz, Myron Kusiak, Harvey Kvile, Kelly Kwiatkowski, Loretta Kwiatkowski,

Angele Kwon, Bob Kyllo, Philippa LaBossiere, Mitzi LaChance, Philip Lafond, Michael Lahure, Cassandra Lai, Edward Lalande, Mahmud Lalani, Jacqueline Lamb, Richard Lameman, John Langille, Carolyn Langpap, Michelle Lapointe, Pamela Lapp, Melvin Lapratt, Robert Larson, Daniel Lastiwka, William Latchuk, Glenda Latham, Joan Latter, Karen Laurin, Steve Laut, Ewen Lawrence, Brian Lawson, Lezlie Lawson, Sharon Layton, Greg Lazaruk, Susan Leak, Margo Lebel, Murray Lechelt, Colleen Lee, Dale Lee, Suzanne Lee, Kevin Legault, Mark Leggett, Mark Lenson, Gary Leong, Stephen Lepp, Gerry Leslie, Marcus Lethaby, Esther Leung, Maurice Levac, Tracy Levasseur, Jean Levesque, Tracy Levia, Shelly Lewchuk, Heather Lichtenbelt, Bonnie Lind, Katherine Linder, Yvonne Linnartz, James Livingston, Dale Lloyd, Kendall Locke, Carolyn Lockyer, Joy Lofendale, Per Lofgren, Shauna Logan, Randal Logelin, Rodney Logozar, Brandice Long, Herb Longworth, Darin Lorenson, Matthew Lorincz, Bob Lorinczy, Nancy Lotocki, Darryl Lowe, Devin Lowe, Gerd Lucas, Michel Lufiauluisu, Wes Lundell, Wendy Lutzen-Askew, Brent Lydiatt, Peter Macdonald, Allan MacKenzie, Graeme MacKenzie, Ken MacKenzie, Ryan MacKenzie, Shawn MacKenzie, Joseph MacKinnon, Susan MacLean, Douglas MacLeod, Anne MacNeil, Marilyn Macoy, Jane Mactaggart, Moises Madalena, Bruce Maddex, Morgan Maddison, Markus Maennchen, Mike Magnusson, Bill Mah, Joey Majerech, Anita Mak, Jim Mak, John Malachowski, Richard Malcolm, Lawrence Malek, James Maloney, Mike Manchen, Leonard Mandrusiak, Darcy Mandziak, Darcy Mann, Phil Mann, Roy Marceniuk, Ronald Marcichiw, Allan Markin, Andrew Marsh, Sally Marshall, Richard May, Toni McCarthy, Trisha McDonald, Christina McGeough, Brenda McGinnis, Frances McGlynn, Robert McGowan, Bruce McGrath, Mavis McGuire, Karen McInnis, Carmen McKay, Kim McKay, Lindsey McKay, Rod McKay, Tim McKay, Keith McKenzie, David McKinnon, Douglas McLachlan, Marla McLean, David McNamara, Elaine McPherson, Casey McWhan, Wendy Measures, Barry Meier, 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Graham Rosso, Barry Rosychuk, Rick Rosychuk, Nicci Roth, Tom Roth, Judy Rotzoll, Richie Rovere, Scott Rowein, Zenita Ruda, Nigel Rusk, Mark Russell, Colin Russett,

Thank you for living the mission statement.

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strategy defined

We significantly grow and maintain our business through a defined growth strategy. We are the operator and have high working interests on the majority of our assets.

	2001	Natural Gas Light Oil Heavy Oil Oil Sands	
	2002		owner operator
near-term	**2003**		core area focus
	2004	Natural Gas Light Oil Heavy Oil Oil Sands	balanced assets
	2005		project inventory
mid-term	**2006**		capital discipline
	2007	Natural Gas Light Oil Heavy Oil Oil Sands	
	2008		
long-term	**2009**		

review of operations

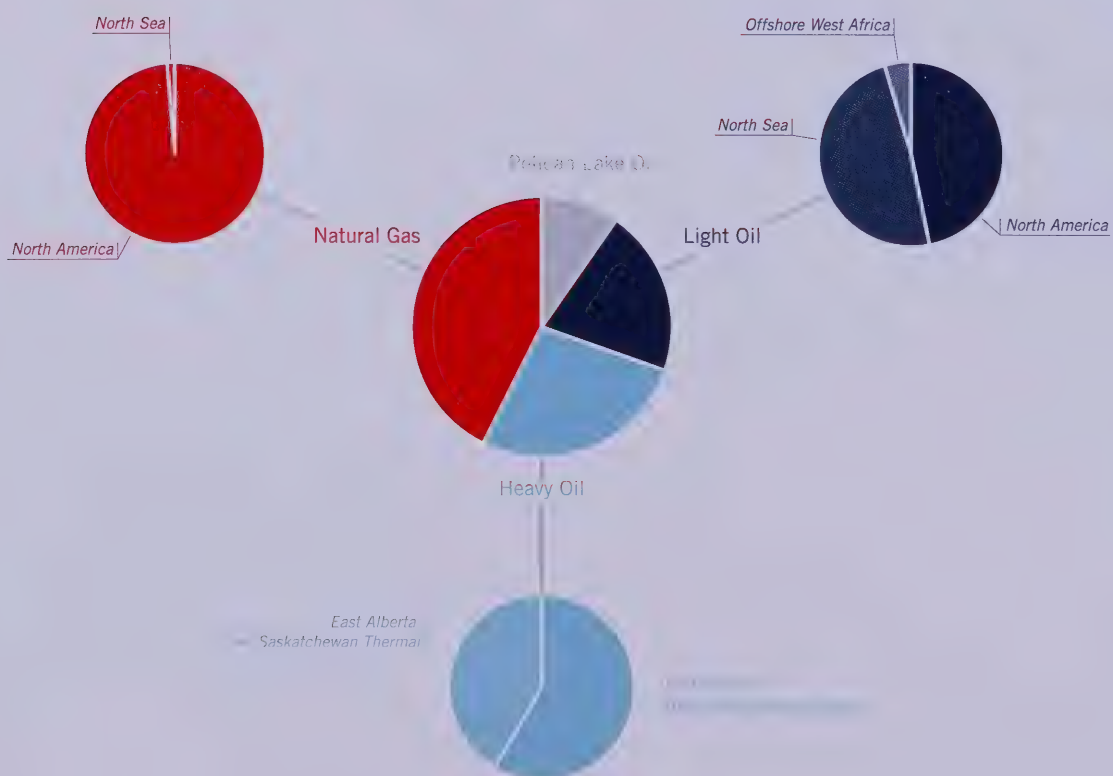
production and sales

Natural gas sales rose significantly during 2001 to average 918 million cubic feet per day, a 16% increase over 2000 sales. The Northeast British Columbia/Northwest Alberta region accounted for the majority of natural gas production with average sales of 368 million cubic feet per day, 40% of the Company's total natural gas production. Production from the Northern Alberta region rose by 7% to average 322 million cubic feet per day. The Southern Alberta region's production amounted to 162 million cubic feet per day, an 8% increase from 2000.

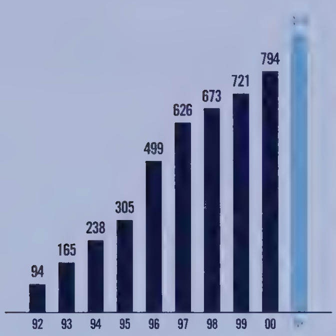
Crude oil and natural gas liquids production averaged 206 thousand barrels per day, an increase of 19% from 2000 production. This reflects the full year inclusion of the mid-2000 Ranger acquisition. Production from the heavy oil area of East Alberta/West Saskatchewan averaged 97 thousand barrels per day, with Pelican Lake contributing an average of 35 thousand barrels per day. Light oil production from North America was 35 thousand barrels per day, in addition to 39 thousand barrels per day contributed by producing fields in the North Sea and offshore West Africa following the Company's first full year of production from these assets.

On a barrels of oil equivalent basis, natural gas production amounted to 43% of total company production, with crude oil and natural gas liquids accounting for the remaining 57%. Heavy oil accounted for 27% of the total barrel of oil equivalent production, with light and Pelican Lake oil providing 30%.

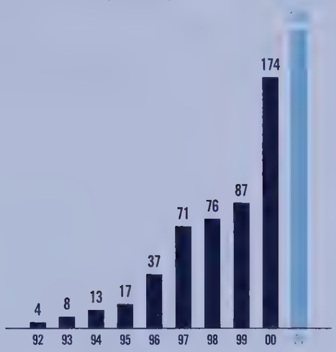
Corporate Production Allocation
2001 Average Production, boe/d (6:1)



Natural gas production
(mmcf/d)



Crude oil and NGLs production
(mbbls/d)



undeveloped land

Canadian Natural owns one of the largest undeveloped land inventories in western Canada. During 2001, the Company's undeveloped net acreage reached 6.5 million net acres, growing by 3% over the 6.3 million net acres of 2000. The additional acreage was primarily added to the Company's core regions of Northern Alberta and Northeast British Columbia/Northwest Alberta, providing the necessary assets for future exploration and exploitation of oil and natural gas reserves.

CANADIAN LANDHOLDINGS

(thousands of acres)	2001			2000		
	Gross Acres	Net Acres	Average Interest %	Gross Acres	Net Acres	Average Interest %
Developed	4,496	3,627	81	4,345	3,398	78
Undeveloped	7,506	6,491	86	7,615	6,276	82
Total	12,002	10,118	84	11,960	9,674	81

NET UNDEVELOPED LAND BY CORE AREA

(thousands of acres)	2001	2000
Northeast British Columbia/Northwest Alberta	1,553	1,442
Northern Alberta	2,573	2,378
Horizon Oil Sands	236	221
East Alberta/West Saskatchewan	1,105	1,090
Southern Alberta	654	539
Southeast Saskatchewan	151	369
United Kingdom North Sea	237	211
Offshore West Africa	1,094	1,528

seismic

With Canadian Natural's emphasis on internally generated prospects, both 2-D and 3-D seismic are required to achieve exploration success. In Canada, Canadian Natural invested $45.8 million in 2001 to acquire new seismic data and to purchase and reprocess existing data. In total, the Company shot 3,200 kilometres of conventional seismic and 288 square kilometres of 3-D data. In addition, more than 6,207 kilometres of conventional seismic and 485 square kilometres of 3-D data was purchased.

Internationally, Canadian Natural uses seismic extensively to determine the viability of its exploration prospects. Since commencing operations outside Canada, the Company has been actively involved in seismic programs covering over 6,760 kilometres of conventional seismic. Additionally, over 53,000 kilometres of conventional data and 4,466 square kilometres of 3-D seismic were purchased.

drilling activity

Canadian Natural drilled 1,092 net wells in 2001, a record high for the Company and a 34% increase over 2000 activity. The drilling program resulted in 476 natural gas wells, 231 oil wells, 337 stratigraphic wells and 16 service wells. Canadian Natural achieved a success rate of 97%, surpassing the Company's excellent performance from 2000. The average working interest of wells drilled in 2001 was 88%, preserving the practice of operating with high ownership.

Canadian Natural responded quickly to high North American natural gas prices by drilling 476 successful natural gas wells, the largest natural gas drilling program ever for the Company. The Company's large and diverse land base afforded Canadian Natural the opportunity to pursue higher risk, deep prospects in British Columbia while pursuing a large complementary low risk program in other core areas.

In North America, Canadian Natural drilled 25 light oil wells. The Company continued with its development of the Pelican Lake property, drilling 100 horizontal wells. Only 103 heavy oil wells were drilled due to low commodity prices resulting from wide heavy oil price differentials. Eighty-nine of these wells were drilled as vertical or slant wells for primary production in the Bonnyville area of Alberta. An additional 14 horizontal well pairs were drilled for the continued development of the Primrose thermal recovery project.

Internationally, in the North Sea, Canadian Natural drilled 2.9 net wells: 2.2 oil wells and 0.6 water injection wells. In Côte d'Ivoire, 1.8 wells were drilled by the Company: 1.2 oil wells and 0.6 water injection wells.

DRILLING ACTIVITY

(number of wells)	2001		2000		1999	
	Gross	Net	Gross	Net	Gross	Net
Natural gas	576	476	474	408	481	458
Oil	270	231	375	333	229	211
Injection/strat tests	356	353	42	38	11	9
Dry	36	32	46	34	54	49
Total	1,238	1,092	937	813	775	727
Success rate		97%		96%		93%

DRILLING ACTIVITY BY CORE REGION

(net wells)	2001	2000	1999
Northeast British Columbia/Northwest Alberta	92	103	74
Northern Alberta	185	245	159
Horizon Oil Sands Project	257	2	–
East Alberta/West Saskatchewan	222	208	136
Southern Alberta	326	238	344
Southeast Saskatchewan	4	13	14
United Kingdom North Sea	3	1	–
Offshore West Africa	2	–	–

Our project inventory defines near, mid and long-term vision for future profitable growth.

reserves and reserve replacements

Canadian Natural retains independent petroleum engineering consultants, Sproule Associates Limited ("Sproule"), to evaluate the Company's proved and probable oil and natural gas reserves and prepare the Evaluation Report on the Company's total reserves. For the year ended December 31, 2001, the independent evaluator's report incorporated 91% of the Company's reserve value with the Company internally evaluating the remaining 9%, which are generally comprised of reserves in properties not currently strategic to the Company's core business areas. The Board of Directors of the Company has a Reserve Committee, which has met with Sproule and carried out independent due diligence procedures with Sproule as to the Company's reserves.

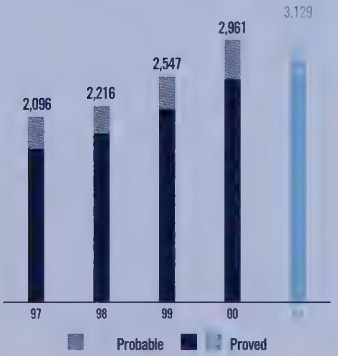
Of interest is the change in proved undeveloped ("PUDs") oil and natural gas liquids ("NGLs") reserves year over year. In North America the percentage of PUDs decreased from 41.6% to 40.6% of total proved reserves. Almost all North American PUDs are attributed to heavy oil reserves. This is due to the multi-zone nature of primary heavy oil developments, as not all zones in each wellbore can be brought on stream at the same time when the well is drilled. Thermal heavy oil has a high degree of reservoir delineation (via stratigraphic test wells) before development and production is brought on stream. This results in a higher percentage of PUDs compared to conventional oil and natural gas reserve bases.

Natural gas PUDs in North America are low at 10.8% of total proved reserves at the end of 2001, compared to 17.9% at the end of 2000. This reflects the Company's focus on increasing natural gas production in 2001 during a period of high commodity prices.

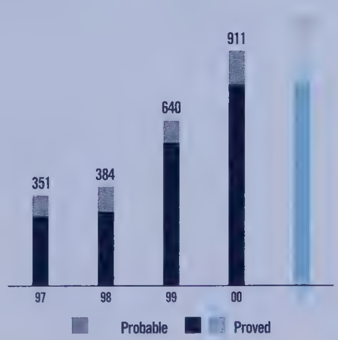
In offshore West Africa, a significant amount of oil reserves (51 million barrels) are booked as probable reserves. These are reserves associated with the waterflood at Espoir in Côte d'Ivoire. These reserves were not booked as proved reserves at year end 2001 as water injection had not commenced. The Company has been injecting water at Espoir since the middle of February 2002, and on successful implementation of the waterflood these reserves will be reclassified as proved.

No reserves have been assigned by the Company or Sproule to the Horizon Oil Sands Project. Canadian Natural's internal estimate of recoverable bitumen is 6 billion barrels. Canadian Natural owns 100% of these estimated reserves with production scheduled to commence in 2007.

Total natural gas reserves
(bcf)



Total crude oil and NGL reserves
(mmbbls)



RESERVES BEFORE ROYALTIES

	December 31, 2001				
	Proved Developed	**Proved Undeveloped**	**Proved Total**	**Probable**	**Total**
Crude Oil and NGLs *(mmbbls)*					
North America	382	262	644	95	739
North Sea	54	31	85	23	108
Offshore West Africa	21	40	61	51	112
	457	333	790	169	959
Natural Gas *(bcf)*					
North America	2,288	278	2,566	349	2,915
North Sea	19	75	94	24	118
Offshore West Africa	17	52	69	27	96
	2,324	405	2,729	400	3,129
Total Reserves *(mmboe 6:1)*	845	400	1,245	236	1,481
Present Value of Reserves *($ millions)*[(1)(2)]					
10% discount	$ 7,850	$ 1,699	$ 9,549	$ 847	$ 10,396
15% discount	$ 6,679	$ 1,177	$ 7,856	$ 642	$ 8,498

	December 31, 2000				
	Proved Developed	**Proved Undeveloped**	**Proved Total**	**Probable**	**Total**
Crude Oil and NGLs *(mmbbls)*					
North America	375	267	642	88	730
North Sea	72	30	102	33	135
Offshore West Africa	3	34	37	9	46
	450	331	781	130	911
Natural Gas *(bcf)*					
North America	1,937	423	2,360	402	2,762
North Sea	31	60	91	23	114
Offshore West Africa	–	66	66	19	85
	1,968	549	2,517	444	2,961
Total Reserves *(mmboe 6:1)*	778	423	1,201	204	1,405
Present Value of Reserves *($ millions)*[(1)(2)]					
10% discount	$ 9,257	$ 2,295	$ 11,552	$ 868	$ 12,420
15% discount	$ 8,066	$ 1,783	$ 9,849	$ 692	$ 10,541

[(1)]Excludes provisions for abandonment costs and income taxes.

[(2)]Value of the probable reserves is reduced by 50% to account for risk.

RESERVES RECONCILIATION

	North America	North Sea	Offshore West Africa	Total
Crude Oil and NGLs *(mmbbls)*				
Proved Reserves				
Reserves, December 31, 1999	554	–	–	554
Extensions and discoveries	67	–	–	67
Property purchases	77	105	36	218
Property disposals	(15)	–	–	(15)
Production	(57)	(6)	(1)	(64)
Revisions of prior estimates	16	3	2	21
Reserves, December 31, 2000	642	102	37	781
Extensions and discoveries	14	–	38	52
Property purchases	16	–	8	24
Property disposals	(1)	–	–	(1)
Production	(61)	(13)	(1)	(75)
Revisions of prior estimates	34	(4)	(21)	9
Reserves, December 31, 2001	644	85	61	790
Probable Reserves				
Reserves, December 31, 1999	86	–	–	86
Extensions and discoveries	1	–	–	1
Property purchases	21	35	9	65
Property disposals	(10)	–	–	(10)
Revisions of prior estimates	(10)	(2)	–	(12)
Reserves, December 31, 2000	88	33	9	130
Extensions and discoveries	(1)	(1)	–	(2)
Property purchases	1	–	19	20
Property disposals	–	–	–	–
Revisions of prior estimates	7	(9)	23	21
Reserves, December 31, 2001	95	23	51	169
Total Reserves, December 31, 2001	739	108	112	959

	North America	North Sea	Offshore West Africa	Total
Natural Gas *(bcf)*				
Proved Reserves				
Reserves, December 31, 1999	2,183	–	–	2,183
Extensions and discoveries	250	–	–	250
Property purchases	267	89	64	420
Property disposals	(41)	–	–	(41)
Production	(290)	(1)	–	(291)
Revisions of prior estimates	(9)	3	2	(4)
Reserves, December 31, 2000	2,360	91	66	2,517
Extensions and discoveries	470	1	–	471
Property purchases	167	–	24	191
Property disposals	(25)	–	–	(25)
Production	(331)	(4)	–	(335)
Revisions of prior estimates	(75)	6	(21)	(90)
Reserves, December 31, 2001	2,566	94	69	2,729
Probable Reserves				
Reserves, December 31, 1999	364	–	–	364
Extensions and discoveries	15	–	–	15
Property purchases	48	21	4	73
Property disposals	(4)	–	–	(4)
Revisions of prior estimates	(21)	2	15	(4)
Reserves, December 31, 2000	402	23	19	444
Extensions and discoveries	9	(1)	–	8
Property purchases	23	–	11	34
Property disposals	(6)	–	–	(6)
Revisions of prior estimates	(79)	2	(3)	(80)
Reserves, December 31, 2001	349	24	27	400
Total Reserves, December 31, 2001	2,915	118	96	3,129

RESERVES CLASSIFICATION BY PRODUCT

(6:1 boe basis as at December 31, 2001)	Proved Developed *(%)*	Proved Undeveloped *(%)*	Proved Total *(%)*	Probable *(%)*	Proved & Probable *(%)*
Light Oil and NGLs					
North America	7	–	7	8	7
North Sea	4	3	7	10	7
Offshore West Africa	2	3	5	21	8
	13	6	19	39	22
Heavy Oil					
North America – Primary	6	2	8	18	10
North America – Thermal	14	17	31	13	28
	20	19	39	31	38
Pelican Lake Oil					
North America	4	1	5	2	5
Total Crude Oil and NGLs					
North America	31	20	51	41	50
North Sea	4	3	7	10	7
Offshore West Africa	2	3	5	21	8
	37	26	63	72	65
Natural Gas					
North America	30	4	34	24	33
North Sea	1	1	2	2	1
Offshore West Africa	–	1	1	2	1
	31	6	37	28	35
Total boe	68	32	100	100	100

FINDING AND ONSTREAM COSTS

	2001	2000	1999	Three Year Total
Capital expenditures *($ millions)*				
Corporate acquisition	$ –	$ 1,687.3	$ –	$ 1,687.3
Net property acquisitions	519.2	150.2	1,422.3	2,091.7
Land acquisition and retention	100.5	79.7	46.2	226.4
Seismic evaluations	94.6	40.5	17.9	153.0
Well drilling, completion and equipping	644.7	524.0	274.8	1,443.5
Pipeline and production facilities	395.0	335.7	143.2	873.9
Total net reserve replacement expenditures	$ 1,754.0	$ 2,817.4	$ 1,904.4	$ 6,475.8
Cost of net reserve replacement including reserve revisions *($/boe)*				
Proved	$ 9.97	$ 7.13	$ 4.90	$ 6.75
Proved and probable	$ 8.47	$ 6.23	$ 4.93	$ 6.19

owner operator
core area focus
balanced assets
project inventory
capital discipline
team commitment
environmental responsibility

To manage the outcome of our planned activities, we own and operate 90% of our western Canadian operations and 60% of our international projects.

RESERVES EVALUATION PRICING MODELS

CRUDE OIL ($Cdn/bbl)	Company Average Price ($US/bbl)	WTI at Cushing, Oklahoma ($Cdn/bbl)	Hardisty Heavy 12° API ($US/bbl)	Brent
December 31, 2001				
Reserves Evaluation Pricing Model[1]				
2002	18.36	19.90	14.41	18.40
2003	20.85	20.64	18.44	19.11
2004	23.44	21.12	21.58	19.29
2005	23.75	21.44	22.13	19.58
2006	24.01	21.76	22.62	19.87
December 31, 2000				
Reserves Evaluation Pricing Model[2]				
2001	28.52	28.20	21.87	26.60
2002	26.41	24.41	21.84	22.78
2003	23.64	21.12	20.54	19.47
2004	23.64	21.44	21.01	19.76
2005	23.59	21.76	20.98	20.06

NATURAL GAS	Company Average Price ($Cdn/mcf)	Henry Hub, Louisiana ($US/mmbtu)	Alberta Plantgate ($Cdn/mmbtu)	British Columbia Plantgate ($Cdn/mmbtu)
December 31, 2001				
Reserves Evaluation Pricing Model[1]				
2002	3.80	2.89	3.80	3.75
2003	4.33	3.24	4.35	4.30
2004	4.32	3.25	4.36	4.26
2005	4.33	3.25	4.36	4.26
2006	4.42	3.29	4.44	4.34
December 31, 2000				
Reserves Evaluation Pricing Model[3]				
2001	8.78	6.34	8.40	9.02
2002	6.00	4.56	5.87	6.09
2003	4.99	3.88	4.91	4.98
2004	4.78	3.73	4.76	4.59
2005	4.69	3.63	4.75	4.34

[1]Sproule January 1, 2002 pricing model adjusted for quality and transportation.

[2]Sproule January 1, 2001 crude oil and NGL pricing model adjusted for quality and transportation.

[3]Natural gas pricing model supplied by the Company based on existing and future natural gas marketing arrangements.

marketing

NATURAL GAS

Average North American natural gas prices in 2001 at NYMEX increased 12% over the previous year to US $4.38 from US $3.91 per million British thermal units ("mmbtu"). Similarly, pricing in Alberta increased 25% to $6.25 per mmbtu from $5.02 in 2000.

During the first quarter of 2001, the demand for natural gas was strong due to increased demand from the electricity generation sector and early winter temperatures. The quarterly average prices were US $7.27 per mmbtu on the NYMEX and $10.34 per mmbtu in Alberta. North American drilling activity was at a record level at the same time as industrial natural gas demand was markedly slowing down under extremely challenging economics.

The tragic events of September exacerbated an already weakened economy and when combined with the record low heating demand, average natural gas pricing for the fourth quarter dropped to US $2.50 per mmbtu on the NYMEX and $3.13 per mmbtu in Alberta.

The surplus of export capacity out of the Western Canadian Sedimentary Basin reached as high as 2 billion cubic feet per day in 2001 and contributed to narrowing the gap between Canadian and United States natural gas prices by US $0.27 per mmbtu on average for the year.

Canadian Natural realized an overall wellhead price of $5.16 per million cubic feet in 2001, up 14% from last year and total sales increased by 16% to 918 million cubic feet per day. Direct sales made up 78% of the portfolio with the remaining 22% split amongst the major supply aggregators. The sales at prevailing market prices represented 88% of the total sales volumes.

Canadian Natural expects 2002 to be challenging with the North American economy in a slow recovery mode. Natural gas drilling activity is significantly down and the Company anticipates 30% fewer industry completions in 2002. The overall yearly decline rates in both Canada and the United States are estimated at 25% and prices are expected to reflect a balanced market by the fourth quarter. The longer term prospects for natural gas are excellent as demand is forecast to resume its 2% annual growth rate based upon anticipated future electricity cogeneration projects.

Canadian Natural's production is forecast to average 1,075 million to 1,125 million cubic feet per day in 2002 and our current pricing outlook should yield an average wellhead price of $3.60 per million cubic feet.

CRUDE OIL

The average crude oil price in 2001 was down 14% from the previous year with the North American benchmark West Texas Intermediate ("WTI") at US $25.91 per barrel and the North Sea benchmark Brent at US $24.43 per barrel.

The pricing level was strong for the first three quarters averaging US $27.75 per barrel for WTI and US $26.16 per barrel for Brent before decreasing 26% in the last quarter to US $20.53 per barrel for WTI and US $19.35 per barrel for Brent. The struggling economy and the September tragedy reduced the yearly growth in demand to a mere 0.3%, its lowest rate in almost twenty years.

The price for Canadian heavy crude oil grades was 30% lower in 2001 with an average differential for benchmark Lloydminster Blend to WTI of US $10.73 per barrel. Early in the year, the demand for refined products was very strong and kept the refining margins at record high levels reaching US $15.00 per barrel thus favouring the lighter grades of crude oil. Tracking the overall economy, crude oil demand weakened steadily throughout the year without a corresponding reduction in worldwide supplies. As refining margins narrowed, so did the heavy oil differentials reaching US $8.50 per barrel for December 2001. The improvement in these differentials was slowed down by the temporary loss of an important United States midwest refinery in mid-August. This refinery is expected to resume full operation in April, 2002.

owner operator
core area focus
balanced assets
project inventory
capital discipline
team commitment
environmental responsibility

We control our spending through focused activity in core areas. Ownership of assets and infrastructure allows us to control the nature and timing of costs incurred.

Canadian Natural's realized oil and natural gas liquids price in 2001 was $24.31 per barrel down 20% from last year while production was up 19% at 206 thousand barrels per day. The portfolio mix of oil and natural gas liquids in 2001 was 50% for light and medium grades, 3% for natural gas liquids and 47% for heavy grades (lower than 15° API).

Canadian Natural expects pricing levels to be unsettled in the early part of 2002 as the economy continues its slow recovery and crude oil supplies decrease to match world demand for products. Early indications demonstrate the commitment from major international producers to reduce production and target a pricing level of US $20.00 per barrel.

This international pricing environment and the expected 30% reduction in drilling activity should ensure a return to more typical economics for heavy oil. From 1996 to 2000 the differential averaged US $5.91 for an average WTI of US $21.30 per barrel. For 2002, differentials in a range of US $4.00 to US $6.00 per barrel for a WTI range of US $18.00 to US $22.00 per barrel are expected.

environment, health and safety, and community

VISION DEFINED

Fundamental to Canadian Natural's long-term growth and success are two very important elements: ethical, socially responsible operations and environmental stewardship.

Our vision in the areas of environment, health and safety, and community is clearly defined:

1. We conduct all operations in a manner that protects the health and safety of employees, contractors, the public and the environment.
2. We work co-operatively with communities, government agencies and interested stakeholders to reduce potential impacts of our operations and maximize opportunities for economic participation.
3. We commit to a long-term presence in the communities where we operate. Our significant business activities contributes to economics and quality of life.
4. We work together with community and industry groups to ensure a better, sustainable energy industry.
5. We integrate environmental and community planning with project design and implementation.

ENVIRONMENT

Canadian Natural's environmental management plan and operating guidelines focus on minimizing the impact of field operations while meeting regulatory requirements and corporate standards.

Our proactive program includes:

1. An annual internal environmental compliance audit and inspection program of our operating facilities;
2. An aggressive suspended well inspection program to support future development or eventual abandonment;
3. Appropriate reclamation and decommissioning standards for wells and facilities ready for abandonment;
4. An effective surface reclamation program. Reclamation certificate applications submitted in 2001 reached 242, more than double those in 2000. Of the 88 applications processed by regulators, a success rate of 100% was achieved;
5. A progressive due diligence program related to groundwater monitoring;
6. A rigorous program related to preventing and reclaiming spill sites; and,
7. A solution gas reduction and conservation program.

Canadian Natural participates in Canada's Voluntary Challenge Registry Inc. ("VCR"). In 2001, the Company received a gold award from VCR for its annual submission. During 2001, Canadian Natural realized annual emission reductions of more than one million tonnes of Carbon Dioxide Equivalent ("CO2E"). These reductions build on 1999 and 2000 programs that resulted in reductions of more than 3.5 million tonnes of CO2E annually. In 2002, Canadian Natural will revise and improve its reporting format to document emissions levels to the baseline year of 1996.

INTERNATIONAL

Canadian Natural's international operations support the International Chamber of Commerce Charter on Sustainable Development.

We have established stringent operating standards in four areas:

1. Using water-based, environmentally friendly drilling muds whenever reasonable;
2. Implementing cost effective ways of reducing greenhouse natural gas emissions per unit of production;
3. Exercising care with respect to all waste produced through effective waste management plans; and,
4. Minimizing produced water volumes onshore and offshore through cost-effective measures and the use of non-toxic or lower toxicity production chemicals whenever practical.

ENVIRONMENTAL IMPACT ASSESSMENTS

As part of our Canadian operations expansion plans, Canadian Natural has undertaken two comprehensive Environmental Impact Assessments ("EIA"). These EIAs also provide long-term management and mitigation strategies to ensure major projects meet environmental, social and economic goals.

An EIA of the Horizon Oil Sands Project will be submitted to regulators in June 2002. All baseline work was completed in 2001. The EIA for the Primrose heavy oil expansion project was submitted to regulators in 2000 and complete at the end of 2001.

owner operator
core area focus
balanced assets
project inventory
capital discipline
team commitment
environmental responsibility

Canadian Natural believes that ethical, socially responsible operations and enviromental stewardship are fundamental to our long-term growth.

HEALTH AND SAFETY

Canadian Natural focuses on the prevention of accidents and injuries through heightened employee and contractor awareness, training and adherence to safe operating procedures. Health and safety teams conduct hundreds of safety and compliance audits of facilities and operations. For each inspection, an audit action plan is prepared and all deficiencies are rectified within 45 days.

In 2001, the health and safety team initiated annual corporate safety meetings in each area of company operations to receive input and identify ways to strengthen health and safety performance. Site-specific emergency response plans were also developed for operating plants and batteries.

COMMUNITY CONSULTATION

Canadian Natural continues to work with local communities in our operating areas and stakeholders related to its major initiatives. In the Horizon Oil Sands Project, the Company is participating in regional working groups to address impacts from oil sands developments. In the Lakeland area of Alberta, the Company helped initiate a regional air and water quality monitoring committee.

Canadian Natural continues to work with Aboriginal communities to reduce possible negative impacts of operations and to ensure individuals and businesses can access the many opportunities created through these operations.

COMMUNITY INVESTMENT PROGRAM

Canadian Natural supported many community-based activities in 2001:

1. A $6.0 million donation in November 2001 to the University of Alberta helped make possible a new state-of-the-art natural resources engineering building. Chairman Allan Markin and Canadian Natural each contributed $3.0 million to the project.
2. The Building Futures Training and Education Program was developed, to be formally launched in 2002. It includes $100 thousand in annual scholarships and supports industry-community partnerships related to regional Petroleum Employment Training.
3. A contribution of $500 thousand was made to the Alberta Children's Hospital.
4. In Angola, West Africa, CNR International bought medicines for a pediatric hospital, helped finance two institutions used to educate and house orphaned children, and supported a charity helping children living on the streets.
5. In Côte d'Ivoire, the Company supported a malaria prevention project and an education program for mothers who are HIV positive. CNR International also provided books for a village primary school and helped fund a disabled children's charity.

assets **defined**

We manage the growth of our asset base by adhering to our defined growth strategy. Our philosophy is to acquire additional working interests and undeveloped land within our core areas of focus. This allows us to be in different stages of exploration and exploitation of our Canadian and international assets at all times.

near-term	2001 2002 2003	Natural Gas	Ladyfern development and Ladyfern lookalikes
		Light Oil	First oil at Espoir
		Heavy Oil	Primrose heavy oil cyclic steam approval
		Oil Sands	Phase 1 engineering design Submit application for regulatory approval
mid-term	2004 2005 2006	Natural Gas	Ladyfern lookalikes development
		Light Oil	Baobab, Kossipo development
		Heavy Oil	Primrose expansion phase 1
		Oil Sands	Begin construction of Project Horizon phase 1
long-term	2007 2008 2009	Natural Gas	Colville Hills natural gas development
		Light Oil	Angola exploration, Côte d'Ivoire satellite pools
		Heavy Oil	Primrose phases 2 and 3 and Gregoire Lake development
		Oil Sands	Phase 1 production – 110 mbbls/d of SCO begin construction phases 2 and 3

review of assets

natural gas

OPERATING PHILOSOPHY

Canadian Natural's impressive growth of natural gas production in 2001 adhered to the Company's strategic plan of annually increasing natural gas production in North America. In 2001, the Company's natural gas production averaged 906 mmcf/d in North America and 12 mmcf/d internationally. The Company is the third largest producer of natural gas in Canada. Canadian Natural's operating philosophy minimizes capital and operating costs. This objective is achieved by having a large and dominant land base, owning and operating the infrastructure and maximizing facility utilization.

The Company's future natural gas production growth will be achieved with an increased component of deeper, high risk, high reward prospects. A strong exploration team has been established to pursue new prospects on the Company's large existing land base and to develop new plays in the Western Canadian Sedimentary Basin.

2001 RESULTS

- Natural gas production averaged 918 mmcf/d, a 16% increase over 2000 production
- Yearly exit rates were 1,070 mmcf/d, up 30% from 2000
- Natural gas production accounted for 43% of the Company's total production
- 99% of the Company's natural gas production is from western Canada and is sold into the North American market
- The Company's natural gas drilling program resulted in 476 net successful natural gas wells which represents 44% of the Company's drilling activity
- 160 net wells were recompleted
- Total capital spending of $325 million was made on 15 acquisitions targeting natural gas assets
- Year-end natural gas reserves totaled 3,129 bcf, an increase of 6% over year-end 2000
- 503 bcf in natural gas reserves were added after production

Northeast British Columbia/Northwest Alberta

Canadian Natural is the largest natural gas producer in British Columbia. The Company's experience in the province, its large undeveloped land base and existing infrastructure affords a significant competitive advantage in the highly prospective region of Northeast British Columbia. Canadian Natural dominates natural gas gathering pipelines and infrastructure in this area; the Company owns and operates a total of 86 natural gas compression facilities and 2 natural gas plants. In this region Canadian Natural produces natural gas from deep, often technically complex horizons, with formation depths ranging from 3 thousand to 10 thousand feet. The main producing regions are:

Helmet: Natural gas charged mid-Devonian limestones occur over a widespread area. Horizontal wells are used to encounter the scattered higher porosity sweetspots, resulting in economic flow rates. The Company has a dominant land base in the area that allows drainage of several sections with each well avoiding competitive drainage. At year end, natural gas production averaged 85 mmcf/d in this area.

Foothills: Canadian Natural targets complex hydrocarbon traps in this highly deformed structural area. Mississippian and Triassic reservoir units are thrust into large traps where their permeability is enhanced by rock fracturing. This can result in flow rates of over 20 mmcf/d and reserves of 10 to 50 bcf per well. The Company produces 37 mmcf/d from the Foothills.

Peace River Arch: The Company has a wide variety of hydrocarbon traps in both sandstone and carbonate reservoirs which allows it to drill for multiple prospects with most wells. By year end, the Company produced 220 mmcf/d from this area.

2001 ACTIVITIES

- Average natural gas production for the area was 368 mmcf/d; a 23% increase over 2000 production and 40% of corporate total natural gas production
- A total of 75 net natural gas wells were drilled and 21 wells were recompleted
- $230 million was spent acquiring an additional 6 natural gas assets including the acquisition of interests in the Helmet area

2002 PLANS

- Drill a total of 40 natural gas wells; 5 exploratory wells will be drilled targeting new Slave Point prospects in the area
- Recomplete 48 wells to prospective horizons
- Allocate $160 million for exploration and development in this core area

Northern Alberta

Natural gas in this core area is produced from shallow, low risk prospects targeting the Mannville and Devonian horizons. There are typically multiple producing targets within each well creating a large inventory of recompletion opportunities that are continuously exploited. Canadian Natural dominates natural gas gathering pipelines and infrastructure in this area, owning and operating a total of 62 natural gas compression facilities and 2 natural gas plants.

2001 ACTIVITIES

- Natural gas production averaged 322 mmcf/d; a 7% increase over 2000 production and representing 35% of corporate total natural gas production
- A total of 54 net natural gas wells were drilled
- 52 wells were recompleted to other productive formations
- $75 million was spent acquiring 5 additional natural gas assets

2002 PLANS

- Drill 26 natural gas wells
- Recomplete 109 wells
- Allocate $24 million in capital spending on exploration and development opportunities

Southern Alberta

The Company's natural gas production in this area is produced from a large variety of horizons with significantly different risks, well costs and depths. Canadian Natural owns and operates 25 natural gas compression facilities and 16 natural gas plants in the area.

2001 ACTIVITIES

- Average natural gas production for the area was 162 mmcf/d; an 8% increase over 2000 production and representing 18% of corporate total natural gas production
- 56% of the production, or 90 mmcf/d comes from shallow horizons in the Medicine Hat, Milk River and Second White Specks formations. Wells targeting these extremely low risk prospects are drilled in large high density programs that allow for a low cost operation. 248 net wells were drilled targeting these zones at an average on-stream cost of $130 thousand per well
- The remaining 44% of production, 72 mmcf/d, results from wells targeting the large number of prospective sand and carbonate reservoirs below the shallow natural gas horizons. 68 net wells were drilled that had the potential for multiple natural gas targets at minimal incremental costs
- $6 million was spent acquiring 3 additional natural gas producing assets
- 57 wells were recompleted to other productive horizons

2002 PLANS

- Drill 40 wells
- Recomplete 53 wells
- Allocate $20 million in capital spending on exploration and development opportunities

East Alberta/West Saskatchewan

Although this core area provides a small percentage of Canadian Natural's total natural gas production, it has provided the Company with an excellent natural gas growth opportunity. The shallow productive horizons in this area are predominantly heavy oil bearing but many natural gas prospects are also present. This affords the Company the ability to explore for both natural gas and heavy oil prospects simultaneously.

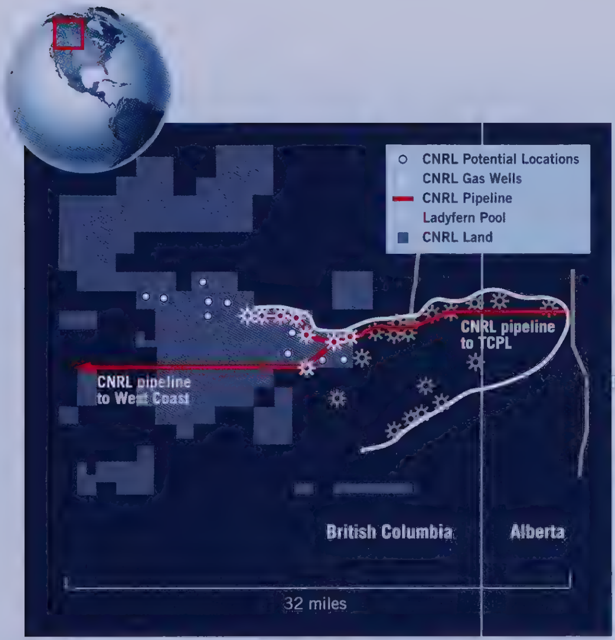
The gathering of solution gas associated with heavy oil production in the area has also provided Canadian Natural with a new source of natural gas sales. Solution gas is now gathered from approximately 220 heavy oil wells resulting in sales of 6 mmcf/d and a reduced amount of vented solution gas.

2001 ACTIVITIES

- Natural gas production averaged 35 mmcf/d; a 17% increase over 2000 production and representing 4% of corporate total natural gas production
- A total of 31 net natural gas wells were drilled
- Acquired additional natural gas assets for a total of $7 million
- 30 wells were recompleted to other productive horizons

2002 PLANS

- Drill 9 wells
- Recomplete 12 wells
- Allocate $22 million in capital spending on exploration and development opportunities



Ladyfern

The Ladyfern Slave Point natural gas pool discovery has provided Canadian Natural with its largest natural gas growth in the Company's history. The prolific production from the pool resulted in the Company achieving year-end production of 150 mmcf/d, despite having no production from the pool at the start of the year. The Ladyfern pool contains approximately 750 bcf of natural gas-in-place, making it one of the largest natural gas pools discovered in the Western Canadian Sedimentary Basin. The natural gas is produced from high porosity reefal carbonates whose permeability has been enhanced by secondary dolomitization along pre-existing fault zones.

Canadian Natural has entered into a production sharing agreement with the other Ladyfern pool producers. This production sharing agreement limits the total production from the field to prevent over capitalization. The production allocation to each producer is based upon the productive capability of each well with a total pool capacity limited to 785 mmcf/d.

2001 ACTIVITIES

- Average natural gas production for the area was 43 mmcf/d, representing 5% of the Company's natural gas production
- A total of 8 net natural gas wells were drilled with a total production capability exceeding 600 mmcf/d
- Canadian Natural's year-end total reserves totaled 190 bcf

2002 PLANS

- Drill 8 natural gas wells targeting the Ladyfern Slave Point pool
- Construct natural gas sales pipeline from British Columbia to Alberta to increase natural gas transportation capacity from the area
- Add compression and dehydration facilities
- Canadian Natural's 2002 production from the pool is predicted to be stable at more than 200 mmcf/d
- A steep production decline is predicted in 2003 as the reservoir pressure drops due to rapid depletion

light oil – north america

OPERATING PHILOSOPHY

In 2001, Canadian Natural achieved its goal of maintaining North American light oil production near 2000 levels. This was accomplished through modest drilling programs, waterflood optimization and implementation and strategic acquisitions within core areas. The Company maximizes the profitability of light oil assets through owning and operating facilities, operating with high working interests, optimizing recovery processes and acquiring only strategic assets. The Company considers light oil growth opportunities to be limited in the mature pools in the Western Canadian Sedimentary Basin and is not predicting growth from these assets.

Many of the Company's light oil pools are produced under waterflood, resulting in significant oil recovery improvements through maintaining reservoir pressure and improving sweep efficiency. Canadian Natural focuses on waterflood optimization through detailed reservoir characterization, analysis of pattern performance, improved well operating practices and improved fluid processing at the surface.

2001 RESULTS

- Light oil and natural gas liquids production averaged 33 mbbls/d, a 3% decrease from 2000 production
- North American light oil production accounted for 9% of the Company's total production
- 25 wells were drilled, 2% of the Company's total wells
- 6 wells were recompleted to access non-producing reserves
- A total of $42 million was allocated to 7 light oil acquisitions

Northeast British Columbia/Northwest Alberta

The majority of Canadian Natural's oil production in this core area is from mature oil pools. The Company owns and operates 15 oil batteries in the area.

Canadian Natural continues to optimize existing waterfloods in the area and are evaluating the implementation of new waterfloods in several pools.

2001 ACTIVITIES

- Yearly oil production averaged 11 mbbls/d, a 15% decrease from 2000
- A total of 8 oil wells were drilled and 2 wells were recompleted
- Acquired 2 additional assets for a total of $5 million

2002 PLANS

- Drill 3 wells
- Allocate $4 million in capital spending for exploration and development opportunities

owner operator
core area focus
balanced assets
project inventory
capital discipline
team commitment
environmental responsibility

Our diversified asset base enables us to shift production emphasis opportunistically in a changing market environment.

Northern Alberta

The main producing property for Canadian Natural in this area is the Gilwood oil pool at Nipisi. This pool has the potential for significant recovery improvements through the optimization of the large waterflood and step-out drilling. In 2001, the Company commenced waterflood optimization and started to realize increased production potential on the flank of the pool.

2001 ACTIVITIES

- Average yearly oil production was 9 mbbls/d, a 55% increase over 2000 levels
- A total of 4 oil wells were drilled
- Continued with analysis and optimization of the Nipisi waterflood
- Acquired 2 additional unit partners in Nipisi bringing Canadian Natural's unit working interest to 79%

2002 PLANS

- Drill 5 wells
- Continue to implement waterflood optimization plan
- Allocate $6 million in capital spending on exploration and development opportunities

Southern Alberta

The majority of Canadian Natural's oil production in this area is from mature oil pools. The Company continues to improve ultimate recovery in these areas through optimizing water injection strategies and maintaining low operating costs through improved fluid handling practices.

The Company continues to utilize acquisitions to consolidate its operating presence in the region.

2001 ACTIVITIES

- Yearly oil production averaged 7 mbbls/d, a 9% decrease from 2000 levels
- A total of 9 oil wells were drilled and 3 wells were recompleted
- A total of $9 million was allocated to 4 acquisitions in this area

2002 PLANS

- Drill 3 wells
- Allocate $3 million in capital spending on exploration and development opportunities

Southeast Saskatchewan

Canadian Natural continued development of oil pools in the Williston Basin through the drilling of infill and step-out wells. The continued exploitation of the area is based on horizontal drilling, waterflood optimization and strategic acquisitions.

2001 ACTIVITIES

- Average yearly oil production was 6 mbbls/d, a 4% decrease from 2000 levels
- A total of 3 horizontal wells and 1 vertical well were drilled in 2001

2002 PLANS

- Drill 5 wells
- Initiate waterflood optimization study for the Steelman field
- Allocate $7 million in capital spending on exploration and development opportunities

light oil – international

OPERATING PHILOSOPHY

Canadian Natural's international light oil activities are in offshore environments in the North Sea, Côte d'Ivoire and Angola. Canadian Natural will employ the same operating philosophy as in western Canada, where the Company controls its activities by maximizing operatorship and working interest in all assets. This allows Canadian Natural to control the pace of development and have tighter control on operating and capital costs. In Côte d'Ivoire and Angola the Company is at these levels. In the North Sea, Canadian Natural continues to pursue the levels of ownership and operatorship it has elsewhere in the Company.

North Sea

Canadian Natural's production in the United Kingdom North Sea is a mix of operated and non-operated properties at various working interests. These properties are very economic and provide significant cash flow contributions to the Company's operations.

2001 ACTIVITIES

- Oil production averaged 36 mbbls/d, a 111% increase in oil due primarily to the mid-year 2000 acquisition of Ranger
- Natural gas production averaged 12 mmcf/d, an 11 fold increase from 2000
- The Company operated Kyle pool was placed onstream at 8 mbbls/d
- Banff field placed back onstream in March 2001 (non-operated)
- Obtained operatorship of the Curlew FPSO, which processes Kyle field production
- Drilled 13 gross (2.2 net) oil wells

2002 PLANS

- Drill Kyle development well
- Drill 17 gross (3.5 net) non-operated wells
- Allocate $79 million for exploration and development opportunities

Offshore West Africa

Angola

The Canadian Natural operated Kiame field in Angola provided the Company's sole offshore West African oil production in 2001. The field has produced much longer than anticipated and final shut-in of the field is scheduled for April 2002.

Angola is a region of significant oil production and presents a major light oil growth opportunity for Canadian Natural. The Company acquired a well established presence in Angola of over ten years through the Ranger acquisition. Canadian Natural is now well positioned to take advantage of future exploration opportunities.

2001 ACTIVITIES

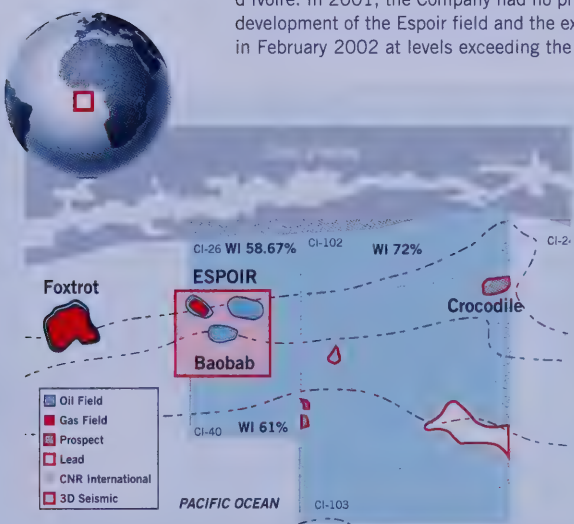
- Kiame field produced an average 3 mbbls/d, exceeding expectations

2002 PLANS

- Shut in Kiame field in April 2002
- Participate in the non-operated Mariposa commitment well (Angola Block 19; 25% working interest)
- Obtain additional operated high working interest exploration blocks in Angola
- Allocate $13 million for exploration and development opportunities

Côte d'Ivoire

The majority of Canadian Natural's 2001 international activities and capital spending occurred in Côte d'Ivoire. In 2001, the Company had no production in Côte d'Ivoire; however activities were focused on the development of the Espoir field and the exploration activities at Baobab. Production commenced at Espoir in February 2002 at levels exceeding the Company's original expectation for the field.



Espoir Development – Baobab Exploration

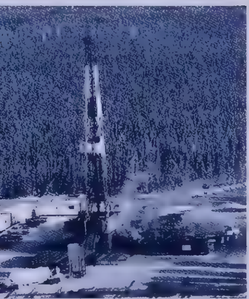
In 2001, Canadian Natural utilized the results of a 3-D seismic survey to find and develop significant light oil reserves. In Côte d'Ivoire the Company's assets are owned (approximately 60% working interest) and operated. Drilling results in 2001, and in particular the Baobab discovery, have established the exploration play from both a structural and reservoir quality viewpoint. More importantly, the results have proven the Baobab trend to be oil versus natural gas bearing. With the 2001 results, Canadian Natural is confident about its future in Côte d'Ivoire, with the potential for 10 years of exploration and development opportunities on the Company's lands.

2001 ACTIVITIES

- Espoir wellhead tower built and installed on time and on budget
- Espoir development batch drilling, 7 gross (4.2 net) wells to intermediate casing, 2 (gross) of which were completed in the reservoir section, on time and on budget
- Espoir Ivoirien FPSO built and sailed to Côte d'Ivoire, on time and on budget
- Installed natural gas pipeline from Espoir wellhead tower to onshore sales system
- Baobab 1X exploration well (61% working interest) drilled and tested at 7 mbbls/d of 23° API oil

2002 PLANS

- Place East Espoir on production and complete development of field to total production of 30 mbbls/d
- Baobab 2X (61% working interest) drilled and tested at rates exceeding 10 mbbls/d
- Delineation well confirms that Baobab recoverable oil from the field is at least 150 mmbbls (700 mmbbls oil in place)
- Drill Kossipo structure, a Baobab seismic look-a-like
- Allocate $111 million for exploration and development opportunities



pelican lake oil

OPERATING PHILOSOPHY

This large, shallow oil pool has been developed exclusively with horizontal wells. This technology minimizes surface disturbance and environmental impact, reduces development costs and results in significantly greater productivity than vertical wells. Canadian Natural owns and currently operates more than 530 horizontal wells in the area. Canadian Natural's Pelican Lake oil production yields netbacks typical of medium oil due to the low operating costs achieved. Operating costs were $2.81/bbl in 2001; costs are minimized since water and sand production are negligible and wells are flowlined to three owned and operated facilities. Canadian Natural is the largest oil producer in the Pelican Lake region.

2001 ACTIVITIES

- Yearly oil production averaged 35 mbbls/d, a 21% increase over 2000 levels
- 100 horizontal wells were drilled with a 100% success rate
- 12 stratigraphic wells were drilled to delineate future drilling prospects
- Acquired the producing assets of one of the two remaining competitors in the area, adding 4 mbbls/d and providing new development opportunities
- Commenced laboratory testing of a tertiary recovery process with emulsion flooding. The Company is forecasting a 6% recovery factor from primary production. The Company's lands in the immediate area contain 3 billion barrels of oil in place, therefore a modest improvement in oil recovery will have a significant impact on recoverable reserves

2002 PLANS

- Drill 72 horizontal wells
- Drill 12 stratigraphic wells
- Initiate field testing of the emulsion flooding process
- Allocate $62 million to exploration and development opportunities

heavy oil

OPERATING PHILOSOPHY

Canadian Natural has become one of the largest heavy oil producers in North America. Canadian Natural's growth of heavy oil production has been achieved through drilling and strategic acquisitions. With this large production growth, comes area dominance. This allows Canadian Natural to reduce capital and operating costs by conducting its drilling programs and operations on a much larger scale. In the primary production area of Lloydminster/Bonnyville, Canadian Natural is now the second largest area producer whereas seven years ago, the Company had no production in the region.

At the Primrose and Tangleflags thermal recovery projects, the Company continues to improve operating practices while optimizing the recovery processes. The large steam generation and oil production facility at its Primrose thermal project continues to provide Canadian Natural with the benefit of adding incremental oil production without the burden of additional facility construction costs. The 55 mbbls/d facility has a current oil throughput of 35 mbbls/d, leaving 20 mbbls/d of capacity for future growth.

Drilling on Canadian Natural's heavy oil properties occurs primarily during periods of favourable heavy oil prices; when prices are low, drilling programs are significantly reduced. Canadian Natural's diverse asset base provides the Company with this flexibility. Larger scale expansions at thermal projects are executed on the basis of long-term commodity prices and are not as sensitive to short-term commodity price fluctuations.

2001 RESULTS

- Oil production averaged 97 mbbls/d, a 7% increase over 2000 production
- 57 mbbls/d were produced by primary recovery mechanisms and 40 mbbls/d were produced by thermal recovery techniques
- Heavy oil production accounted for 27% of the Company's total production
- 103 net oil wells were drilled, 9% of the Company's total wells; an additional 68 stratigraphic wells were also drilled to help delineate prospective reservoir. A 99% success rate was achieved for the wells drilled for production
- 207 wells were recompleted to access non-producing reserves or to optimize productivity
- 5 acquisitions totaling $19 million

Primary: East Alberta/West Saskatchewan

The area geology provides multiple shallow producing targets at depths of less than 2 thousand feet. The use of screw pumps results in typical rates from new wells averaging 50 to 100 bbls/d. Oil is trucked from individual wells or centrally drilled well pads to central treating facilities that are sales pipeline connected. Canadian Natural owns and operates 15 oil batteries in the region which helps minimize operating and treating costs. A strong focus on operating costs is paramount to maximizing heavy oil netbacks. The Company achieves this by having a large production base, owning the facilities and infrastructure and drilling only the most productive prospects.

2001 ACTIVITIES

- Oil production averaged 57 mbbls/d, maintaining 2000 production levels
- 89 oil wells were drilled
- 199 wells were recompleted to access other productive horizons

2002 PLANS

- Drill 21 wells
- Recomplete 202 wells
- Allocate $17 million in capital spending on exploration and development opportunities

Thermal: East Alberta/West Saskatchewan

Oil in the Cold Lake region does not flow at reservoir temperatures and requires heating to mobilize it. Steam is injected into the oil deposit to transfer heat to the oil. Canadian Natural only targets shallow (less than 2 thousand feet), thick (30 – 60 feet), and very large deposits for thermal recovery since the cost of steam generation is too prohibitive to develop thinner, smaller oil prospects. In the Company's operations two distinct recovery processes are employed: cyclic steam stimulation ("CSS") and steam assisted gravity drainage ("SAGD").

Canadian Natural is the second largest producer of thermal oil in Canada and operates three thermal projects:

Primrose: This project in the Cold Lake region of Alberta produces more than 37 mbbls/d. In the Clearwater formation, the Company utilizes horizontal wells with the CSS process for oil recovery. The 350 active horizontal wells reduce capital costs and also minimize surface disturbance. In the Grand Rapids formation that is also present at Primrose, Canadian Natural has established a successful commercial SAGD project. There are 12 active horizontal well pairs employing this recovery scheme. The regulatory application for the expansion of operations at Primrose submitted in 2000 was finalized during 2001. This application seeks approval for converting the remaining 248 low pressure wells to high pressure steaming and the construction of a new 60 mbbls/d facility. Approval is expected in 2002. Construction of the new facility is currently planned to commence in 2004-2005. The Company estimates that at Primrose there are potentially more than 850 mmbbls of recoverable reserves on Canadian Natural lands.

Burnt Lake: The Company continues to operate this SAGD pilot project on lands immediately adjacent to Primrose. The SAGD test results will be used in conjunction with the Primrose CSS results to determine the optimum economic process for commercial development at this site. Utilizing SAGD there are potentially more than 300 mmbbls of recoverable reserves at Burnt Lake.

Tangleflags: The project in west Saskatchewan produces 2 mbbls/d utilizing horizontal wells and the SAGD process. This project has been in operation since 1988 and recoveries in the pool are approaching 45% of the original oil in place.

Canadian Natural also has significant thermal opportunities on approximately 100 thousand acres of undeveloped lands in the Fort McMurray region of Alberta. Initial delineation drilling has established excellent SAGD development potential on the Company's leases at Gregoire Lake and Horizon.

2001 ACTIVITIES

- Yearly oil production averaged 40 mbbls/d, a 15% increase over 2000 levels
- 14 horizontal producer/injector well pairs (28 wells) were drilled as the first phase of Canadian Natural's commercial SAGD project
- 68 stratigraphic wells were drilled to delineate additional reservoir for future commercial development
- 60 horizontal CSS wells were converted to high pressure steam injection, improving their productivity by 50%
- Initiated testing of steam generation utilizing produced oil rather than natural gas
- 8 wells were recompleted to access other productive horizons

2002 PLANS

- Optimize facility operations to decrease usage of purchased fuel gas
- Drill 155 stratigraphic wells to delineate the reservoir for future development
- Convert 80 wells to high pressure steaming (contingent upon regulatory approval)
- Commence testing of facilities to gather produced solution gas
- Continue to delineate prospective thermal leases at Gregoire Lake and Horizon

owner operator
core area focus
balanced assets
project inventory
capital discipline
team commitment
environmental responsibility

Our core area focus concentrates our resources on those assets where we can extract the most value.

midstream

OPERATING PHILOSOPHY

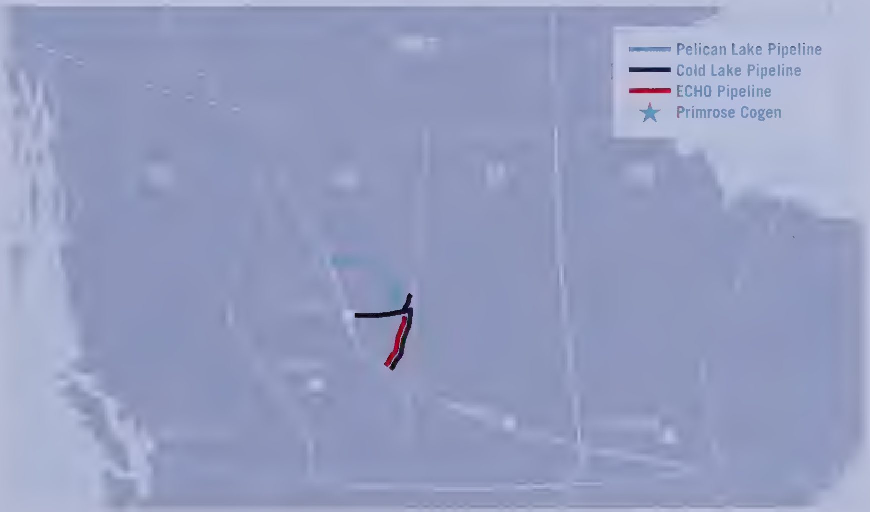
Canadian Natural's midstream asset portfolio is comprised of three crude oil pipeline systems and a 50% ownership in an 84 megawatt cogeneration plant at the Company's steam generation facilities at Primrose. Together, the 100% owned and operated ECHO Pipeline, 62% owned and operated Pelican Lake Pipeline and the 15% owned Cold Lake Pipeline transport in excess of 75% of Canadian Natural's heavy oil production to the international mainline liquids pipelines.

2001 ACTIVITIES

- Acquired additional 15% interest in the Pelican Lake Pipeline
- Extended ECHO Pipeline in December, to transport the volumes from its Beartrap and Elk Point oil batteries fully utilizing pipeline capacity at 58 mbbls/d
- Completed Cold Lake Pipeline expansion in December allowing for total pipeline capacity of 225 mbbls/d of oil to each of Edmonton and Hardisty, Alberta

2002 PLANS

- Allocate $9 million to develop midstream opportunities



oil sands – horizon

OPERATING PHILOSOPHY

Canadian Natural owns and operates leases covering 236 thousand acres in the Fort McMurray region of northern Alberta. Drilling to date indicates an estimated 16 billion barrels of bitumen in place, with approximately 6 billion barrels being recoverable under existing technologies.

The Company has developed a project execution strategy which phases in the production from the project over a five-year period. First oil is expected in the latter half of 2007 at a production rate of 110 mbbls/d of synthetic light crude oil ("SCO"). The second phase of production is expected in late 2009 with an incremental 45 mbbls/d of SCO onstream. The third and final phase of development is expected in 2011 to bring total production to 232 mbbls/d of SCO.

Product marketing studies have been completed by Canadian Natural to forecast SCO sales potential and the associated pricing resulting from the production quantities of Horizon and other operator's oil sands project expansions. Current product pricing, capital and operating cost estimates for the project show a range of returns of 14% to 22% based upon long-term average WTI assumptions of US $18.00 to US $26.00.

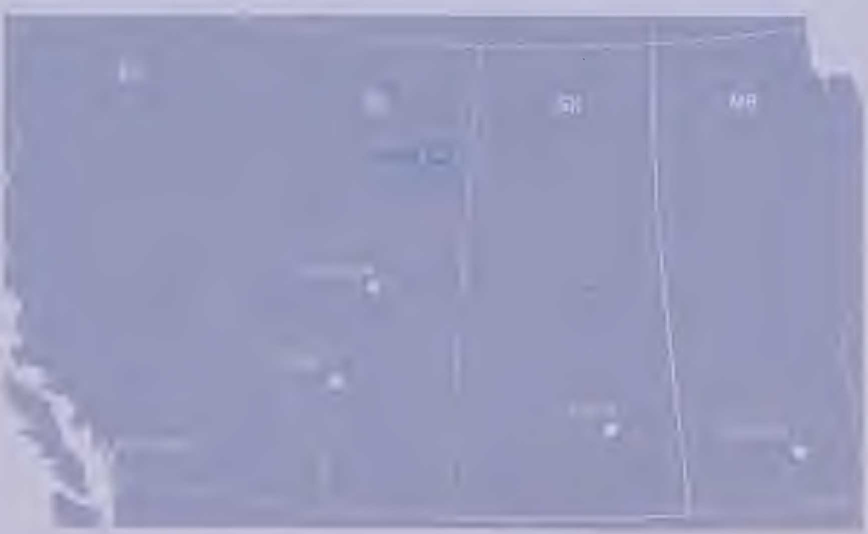
The Company's approach for this project is to extensively evaluate new technology options and pre-design the infrastructure prior to construction. In this way, Canadian Natural can increase cost certainty before significant activity begins. With respect to bitumen upgrading, the Company continues to evaluate various options, including both full and partial upgrading.

2001 ACTIVITIES

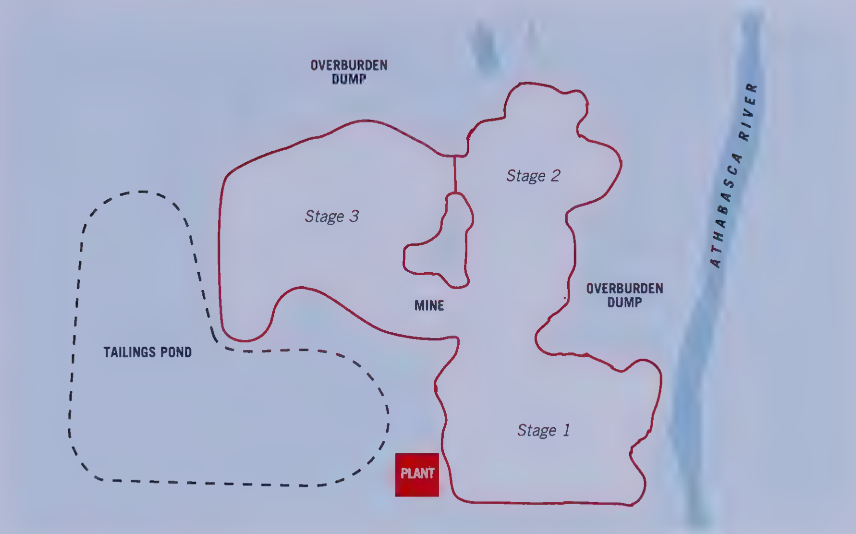
- Completed feasibility study and technology review; project baseline technologies include conventional mining methods and extraction processes used by other operators in the area
- Continued to build a project team with experienced professionals with significant oil sands experience
- Drilled 257 stratigraphic test wells to further delineate the ore body and confirm resource quality and quantity

2002 PLANS

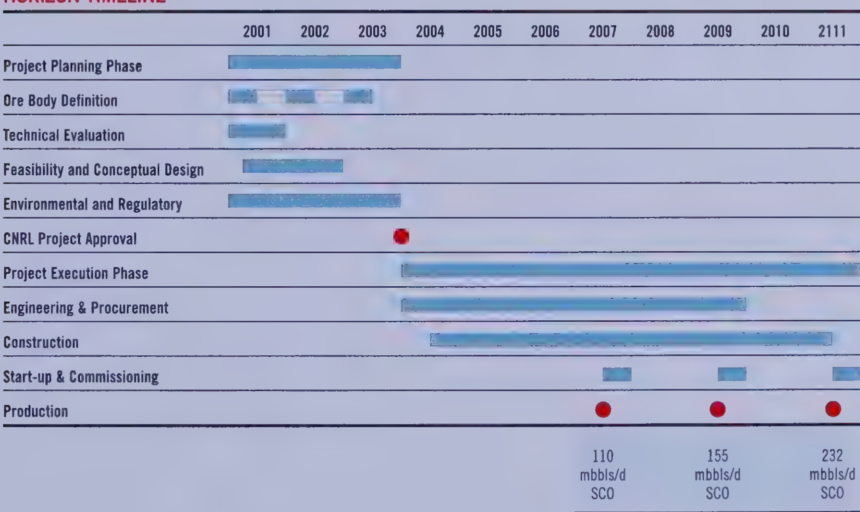
- Complete phase two of engineering or Design Basis Memorandum, which will further detail the Scope Definition, refine the Execution Strategy, and refine the Cost Estimate
- Drill 380 geological stratigraphic wells focusing on the mining area of the first ten years of production
- File regulatory applications in mid-2002 with government approvals expected in 2003
- Continue stakeholder consultations
- Total capital spending planned at $87 million



HORIZON INITIAL MINE AND PLANT LAYOUT



HORIZON TIMELINE



performance

We seek profitable growth by operating under a defined corporate strategy with a balanced asset base capable of long-term development and product delivery. In order to achieve continued positive growth we exercise discipline in our capital spending and manage our costs consistently throughout all industry cycles.

management's discussion and analysis

Canadian Natural Resources Limited ("Canadian Natural" or the "Company") achieved significant results in many areas of its financial and operational performance in 2001 as a result of its balanced production profile and inventory of development projects. These results include natural gas production exceeding one billion cubic feet per day in the fourth quarter, the continued development of the Company's international assets and making significant progress on its world class Horizon oil sands project.

The following discussion details Canadian Natural's 2001 financial results compared to 2000 and 1999, including its capital program, and outlook for 2002.

Management's discussion and analysis ("MD&A") of the financial condition and results of operations of Canadian Natural should be read in conjunction with the Company's audited consolidated financial statements and related notes for the year ended December 31, 2001. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). A reconciliation of Canadian GAAP to United States GAAP is included in note 15 to the consolidated financial statements. All dollar amounts are referenced in Canadian dollars, except as noted otherwise. The calculation of barrels of oil equivalent ("boe") is based on a conversion ratio of six thousand cubic feet of natural gas to one barrel of oil to estimate relative energy content. Certain information regarding the Company contained herein may constitute forward-looking statements under applicable securities laws. Such statements are subject to known or unknown risks and uncertainties that may cause actual results to differ materially from those anticipated or implied in the forward-looking statements.

NET EARNINGS AND CASH FLOW

	2001	2000	1999
Net earnings attributable to			
common shareholders[1] *($ millions)*	$ 698.2	$ 782.2	$ 200.2
Per share – basic	$ 5.76	$ 6.70	$ 1.93
– diluted	$ 5.56	$ 6.50	$ 1.90
Cash flow from operations attributable to common			
shareholders[1] *($ millions)*	$ 1,920.0	$ 1,883.6	$ 723.5
Per share – basic	$ 15.83	$ 16.14	$ 6.96
– diluted	$ 15.25	$ 15.64	$ 6.85
Net earnings as a percentage of cash flow[1]	36.4%	41.5%	27.7%
Debt to cash flow[2]	1.4x	1.3x	2.9x
Debt to book capitalization[2]	42.5%	45.4%	53.3%
After tax return on average common			
shareholders' equity[2]	20.1%	32.4%	13.2%
After tax return on average capital employed	13.0%	18.1%	8.4%

[1] After dividend on preferred securities.
[2] Includes preferred securities as debt equivalents.

Net earnings attributable to common shareholders decreased 11% in 2001 to $698.2 million, down from $782.2 million in 2000 and up from $200.2 million in 1999. The decrease in net earnings resulted from higher depletion costs associated with the Company's increased emphasis on natural gas drilling and completion in North America as well as higher depletion costs in the North Sea and offshore West Africa segments acquired with Ranger Oil Limited ("Ranger") in 2000. Net earnings also decreased as a result of a $24.1 million loss on sale of United States assets in the fourth quarter of 2001. These assets were acquired in the Ranger acquisition and the sale represents the culmination of management's original intent to dispose of these properties. The decrease in net earnings was partially offset by a reduction in certain Canadian provinces' corporate income tax rate in 2001.

Cash flow from operations attributable to common shareholders increased 2% to $1,920.0 million ($15.83 per share), up from $1,883.6 million ($16.14 per share) in 2000 and $723.5 million ($6.96 per share) in 1999. The increase in cash flow resulted from higher natural gas prices and higher production volumes. In 2001, Canadian Natural's average price per thousand cubic feet of natural gas increased to $5.16 from $4.53 in 2000 (1999 – $2.36). Production volumes increased 17% to 359,347 boe per day from 305,987 boe per day in 2000 (1999 – 206,922 boe per day).

Gross Revenue

	2001	2000	1999
Oil and liquids *($ millions)*	$ 1,832.8	$ 1,906.4	$ 666.3
North America *($/bbl)*	$ 21.00	$ 28.15	$ 21.04
North Sea *($/bbl)*	$ 38.66	$ 44.61	$ –
Offshore West Africa *($/bbl)*	$ 33.57	$ 45.77	$ –
Company average *($/bbl)*	$ 24.31	$ 29.99	$ 21.04
Natural gas *($ millions)*	$ 1,728.6	$ 1,316.1	$ 620.5
North America *($/mcf)*	$ 5.19	$ 4.53	$ 2.36
North Sea *($/mcf)*	$ 2.51	$ 3.66	$ –
Company average *($/mcf)*	$ 5.16	$ 4.53	$ 2.36
Total gross revenue *($ millions)*	$ 3,561.4	$ 3,222.5	$ 1,286.8
($/boe)	$ 27.15	$ 28.77	$ 17.03
Percentage of gross revenue			
Oil and liquids	51.5%	59.2%	51.8%
Natural gas	48.5%	40.8%	48.2%

Analysis of Changes in Gross Revenue

		Changes due to			Changes due to		
($ millions)	**1999**	**Volumes**	**Prices**	**2000**	**Volumes**	**Prices**	**2001**
North America							
Oil and liquids	$ 666.3	$ 522.2	$ 402.5	$1,591.0	$ 122.5	$ (434.1)	$1,279.4
Natural gas	620.5	63.9	629.7	1,314.1	183.3	220.0	1,717.4
	1,286.8	586.1	1,032.2	2,905.1	305.8	(214.1)	2,996.8
North Sea							
Oil and liquids	–	280.8	–	280.8	309.5	(78.5)	511.8
Natural gas	–	2.0	–	2.0	14.3	(5.1)	11.2
	–	282.8	–	282.8	323.8	(83.6)	523.0
Offshore West Africa							
Oil and liquids	–	34.6	–	34.6	22.1	(15.1)	41.6
	–	34.6	–	34.6	22.1	(15.1)	41.6
Total							
Oil and liquids	666.3	837.6	402.5	1,906.4	454.1	(527.7)	1,832.8
Natural gas	620.5	65.9	629.7	1,316.1	197.6	214.9	1,728.6
	$1,286.8	$ 903.5	$1,032.2	$3,222.5	$ 651.7	$ (312.8)	$3,561.4

Canadian Natural's gross revenue rose 11% to $3,561.4 million from $3,222.5 million in 2000 (1999 – $1,286.8 million). In the year 2001, 16% of Canadian Natural's total revenue was generated outside of North America compared to 10% in the year 2000, with the North Sea accounting for 15% (2000 – 9%) and offshore West Africa accounting for 1% (2000 – 1%).

The world oil price declined in 2001 due to the effects of weakening market demand. The West Texas Intermediate ("WTI") oil price decreased 14% to average US $25.91 per barrel, down from US $30.20 per barrel in 2000 (1999 – US $19.24 per barrel). At the same time, the heavy oil differential averaged US $10.73 per barrel, up from US $8.23 per barrel in 2000 (1999 – US $4.30 per barrel). The Company was able to mitigate some of the effects of lower WTI prices and the higher heavy oil differential through the use of costless oil collars. The costless oil collars and other arrangements entered into by the Company to fix a portion of the price realized from the sale of oil increased the price by $0.86 per barrel in 2001 ($1.89 and $1.22 reductions per barrel in 2000 and 1999, respectively). Canadian Natural's oil price decreased 19% to average $24.31 per barrel during the year, down from $29.99 per barrel in 2000 (1999 – $21.04 per barrel).

The sales price of natural gas increased to historically high levels as Canadian Natural received $5.16 per thousand cubic feet in 2001, a 14% increase over the 2000 price of $4.53 per thousand cubic feet (1999 – $2.36 per thousand cubic feet). The first half of 2001 saw record high natural gas prices due to the increase in demand for natural gas as a result of cold winter temperatures, low inventory levels, an increase in natural gas-fired power generation and increases in export capacity. In the second half of 2001, the natural gas market changed dramatically due to lower demand in the North American market and an increase in natural gas storage levels. Arrangements entered into by Canadian Natural to fix the price of a portion of its natural gas sales resulted in a reduction of $0.29 per thousand cubic feet (reductions per thousand cubic feet of $0.39 and $0.16 in 2000 and 1999, respectively).

Daily Production

	2001	2000	1999
Oil and liquids *(bbls/d)*			
North America	166,675	154,331	86,750
North Sea	36,252	17,195	–
Offshore West Africa	3,396	2,065	–
Total	206,323	173,591	86,750
Natural gas *(mmcf/d)*			
North America	906	793	721
North Sea	12	1	–
Total	918	794	721
Barrels of oil equivalent *(boe/d)*	359,347	305,987	206,922
Product mix			
Light and Pelican Lake oil	30%	28%	21%
Heavy oil	27%	29%	21%
Natural gas	43%	43%	58%

Canadian Natural's daily oil and liquids production increased 19% to average 206,323 barrels in 2001 from 173,591 barrels in 2000 (1999 – 86,750 barrels). The increase in total oil and liquids production resulted from a full year of production from properties acquired in the third quarter of 2000 with Ranger. The late 2001 decline in world oil prices, combined with the unusually high heavy oil differential, resulted in Canadian Natural deciding to curtail its heavy oil production, delay heavy oil drilling and extend the steaming cycles at Primrose. North Sea oil and liquids production averaged 36,252 barrels per day in 2001 (2000 – 17,195 barrels per day). Production from this segment increased due to the tie-in of the Company's operated Kyle field and the re-commencement of production from the Banff field. In September 2000, the floating production, storage and offtake ("FPSO") vessel had been removed from the Banff field for refitting. Offshore West Africa production increased 64% to average 3,396 barrels of oil per day in 2001 compared to 2,065 barrels per day in 2000. Production in this segment is derived from the Kiame field located in Angola. The Company has given notification to the Angolan government that production from the Kiame field will cease in April 2002. Additional production from this segment will come from the completion of the Espoir field, in Côte d'Ivoire, which commenced production February 4, 2002.

Natural gas continues to be the largest element of the Company's overall production, accounting for 46% of total production in the fourth quarter and 43% of the total 2001 production. North America accounts for over 98% of all of the Company's natural gas production. Daily natural gas production increased 14% to 906 million cubic feet from 793 million cubic feet in 2000 (721 million cubic feet in 1999) in this segment. The 2001 increase in natural gas production was due to a full year of production from the Ranger acquisition, an emphasis on natural gas drilling and a complementary acquisition program. The Company's natural gas drilling program saw the drilling of 476 natural gas wells with the most significant discovery being at Ladyfern in British Columbia, where the Company drilled and completed seven wells in 2001. Six of the Ladyfern wells are each capable of producing over 100 million cubic feet per day; however, production continues to be restricted due to pipeline limitations. The acquisition program resulted in the consolidation of property interest in the Helmet area of northeastern British Columbia. Natural gas production in the North Sea increased to average over 12 million cubic feet per day in 2001. The increase is a result of the re-commencement of production from the Banff field on March 29, 2001. In addition, the Company's operated Kyle field was tied-in during the second quarter of 2001.

Royalties

	2001	2000	1999
Oil and liquids *($ millions)*	$ 163.7	$ 193.9	$ 71.2
North America *($/bbl)*	$ 2.22	$ 3.17	$ 2.25
North Sea *($/bbl)*	$ 2.10	$ 2.40	$ –
Offshore West Africa *($/bbl)*	$ 0.93	$ –	$ –
Company average *($/bbl)*	$ 2.17	$ 3.05	$ 2.25
Natural gas *($ millions)*	$ 416.6	$ 312.3	$ 116.7
North America *($/mcf)*	$ 1.26	$ 1.08	$ 0.44
Company average *($/mcf)*	$ 1.25	$ 1.08	$ 0.44
Total royalties *($ millions)*	$ 580.3	$ 506.2	$ 187.9
($/boe)	$ 4.42	$ 4.51	$ 2.49
Percentage of revenue			
Oil and liquids	8.9%	10.2%	10.7%
Natural gas	24.1%	23.7%	18.8%

Oil and liquids royalties in North America decreased to $2.22 per barrel, down from $3.17 per barrel in 2000 and $2.25 per barrel in 1999 due to lower world oil prices and the continuing benefit of a lower royalty structure on the Company's production of primary and thermal heavy oil. The majority of Canadian Natural's oil sands projects continued to benefit from the Alberta program to promote development of oil sands resources, which provides a reduced royalty rate until an oil sands project recovers its capital costs. It is anticipated that two of the Company's oil sands projects will reach payout in 2002. North Sea oil and liquids royalties decreased to $2.10 per barrel in the year 2001 from $2.40 per barrel in 2000 as a result of lower oil prices, but remained relatively consistent as a percentage of revenue at 5.4% compared to 5.3% in 2000. Offshore West Africa oil and liquids royalties were incurred in the Kiame field due to the field reaching payout in the second quarter of 2001. Royalties as a percentage of oil and liquids revenue decreased to 8.9% in 2001, compared to 10.2% in 2000 (1999 – 10.7%).

Natural gas royalties for the Company increased to $1.25 per thousand cubic feet in the year 2001 compared to the prior year due to the overall increase in natural gas prices. North American natural gas royalties are sensitive to price changes and increased as a percentage of gross sales due to the higher sales price received in 2001. Natural gas royalties for this segment increased to 24.3% of revenue or $1.26 per thousand cubic feet in 2001 from 23.8% of revenue or $1.08 per thousand cubic feet in 2000 (1999 – 18.8% or $0.44 per thousand cubic feet). In the North Sea, the Company's natural gas production is derived from the non-royalty paying Banff and Kyle fields.

Production Expense

	2001	2000	1999
Oil and liquids *($ millions)*	$ 558.9	$ 405.0	$ 155.1
North America *($/bbl)*	$ 6.78	$ 5.93	$ 4.90
North Sea *($/bbl)*	$ 9.00	$ 8.66	$ -
Offshore West Africa *($/bbl)*	$ 21.77	$ 20.41	$ -
Company average *($/bbl)*	$ 7.42	$ 6.38	$ 4.90
Natural gas *($ millions)*	$ 171.6	$ 127.9	$ 96.9
North America *($/mcf)*	$ 0.50	$ 0.44	$ 0.37
North Sea *($/mcf)*	$ 0.94	$ 0.79	$ -
Company average *($/mcf)*	$ 0.51	$ 0.44	$ 0.37
Total production expense *($ millions)*	$ 730.5	$ 532.9	$ 252.0
($/boe)	$ 5.57	$ 4.76	$ 3.34

North American oil and natural gas production expenses increased to $5.00 per boe compared with $4.41 per boe in 2000 (1999 – $3.34 per boe) due to higher costs associated with fuel, power and processing incurred during the first half of the year. North American oil and liquids production expenses increased 14% to $6.78 per barrel from $5.93 per barrel in 2000 (1999 – $4.90 per barrel). The increase in oil and liquids production expenses is related to the cost of natural gas used to produce steam that is injected into the oil formation for the production of thermal heavy oil at Primrose. The costs of processing thermal heavy oil in Canada decreased in the last half of the year as a result of declining natural gas prices. North American natural gas production expenses increased 14% to $0.50 per thousand cubic feet in 2001 from $0.44 per thousand cubic feet in 2000 (1999 – $0.37 per thousand cubic feet). This increase was due to higher fuel, power and processing costs incurred during the first half of the year and a larger proportion of natural gas production from higher production expense areas in British Columbia.

North Sea production costs have increased 3% to $8.82 per boe in 2001 from $8.60 per boe in 2000. North Sea oil and liquids production costs have increased to $9.00 per barrel in 2001 from $8.66 per barrel in 2000. The increase is a result of the Columba B and D fields reaching a production milestone during the year, thereby giving rise to higher tariff rates on a go forward basis. Offshore West Africa production expense averaged $21.77 per barrel of oil in 2001 compared to $20.41 per barrel in 2000 due to decreased production over which fixed costs associated with the FPSO in Angola are allocated.

Depletion, Depreciation and Amortization

($ millions, except boe amounts)	2001	2000	1999
North America	$ 750.9	$ 587.7	$ 384.3
North Sea	129.0	54.4	-
Offshore West Africa	23.9	2.5	-
Total	$ 903.8	$ 644.6	$ 384.3
($/boe)	$ 6.89	$ 5.75	$ 5.08

Depletion, depreciation and amortization increased 40% to $903.8 million from $644.6 million in 2000 (1999 – $384.3 million). This increase was due to the higher costs associated with the Company's

increased emphasis on natural gas drilling and completion in North America as well as higher depletion costs in the North Sea and offshore West Africa segments acquired with Ranger. The rate on a per boe basis increased 20% to $6.89 from $5.75 in 2000 (1999 – $5.08).

Administration Expense

	2001	2000	1999
Gross costs *($ millions)*	$ 109.9	$ 67.8	$ 37.6
($/boe)	$ 0.84	$ 0.61	$ 0.50
Administration *($ millions)*	$ 37.6	$ 27.2	$ 17.0
($/boe)	$ 0.29	$ 0.25	$ 0.23

Gross administration expense increased to $0.84 per boe from $0.61 per boe in 2000 (1999 – $0.50 per boe) mainly due to higher staffing levels associated with the growth in production and the acquisition of Ranger in July 2000. Gross administration expense also increased as a result of the higher costs associated with the Company's international operations. Net administration expense, after operator recoveries and capitalized overhead relating to exploration and development in the North Sea and offshore West Africa segments, increased to $0.29 per boe in 2001 from $0.25 per boe in 2000 (1999 – $0.23 per boe).

Interest Expense

	2001	2000	1999
Total interest expense *($ millions)*	$ 137.8	$ 162.3	$ 90.1
($/boe)	$ 1.05	$ 1.45	$ 1.19
Average effective interest rate	5.4%	6.4%	5.4%
EBITDA interest coverage	15.8x	13.3x	9.2x

Interest expense decreased to $137.8 million ($1.05 per boe) from $162.3 million ($1.45 per boe) in 2000 (1999 – $90.1 million and $1.19 per boe). The decrease in interest expense was due to lower debt levels in the first three quarters of 2001 and the decrease in the average effective interest rate to 5.4% from 6.4% in 2000 (1999 – 5.4%). Fixed-rate long-term debt as a percentage of total debt outstanding remained relatively stable at 21% (after interest rate swaps) as at December 31, 2001, compared to 23% at the end of 2000 (1999 – 6%), which enabled the Company to benefit from the decrease in interest rates in 2001.

Foreign Exchange

Canadian Natural's debt denominated in United States dollars increased to US $899.0 million, mainly due to the Company issuing US $400 million of United States debt securities, maturing July 15, 2011, and bearing interest at 6.70%. United States dollar denominated debt represented 53% of the total debt outstanding at December 31, 2001. This compares with US $509.0 million or 31% of total debt outstanding at the end of 2000 (1999 – US $196.0 million or 13%). Due to the greater amount of United States dollar denominated debt outstanding and the weakening Canadian dollar during the year 2001, the balance of deferred unrealized foreign exchange losses increased to $61.9 million from $13.8 million in 2000 (1999 – $0.3 million). Unrealized foreign exchange losses charged to earnings amounted to $16.0 million in 2001 compared to $2.6 million in 2000 (1999 – $2.2 million).

Realized foreign exchange gains amounted to $1.3 million in 2001 and $0.2 million in 2000 (1999 – $0.4 million realized foreign exchange loss).

Taxes

($ millions)	2001	2000	1999
Taxes other than income taxes			
Current	$ 69.3	$ 57.1	$ 8.1
Deferred	(0.2)	(7.6)	–
Total	$ 69.1	$ 49.5	$ 8.1
Current income tax			
North Sea	$ 61.8	$ 33.7	$ –
Large Corporations Tax	15.1	14.7	7.8
Total	$ 76.9	$ 48.4	$ 7.8
Future income tax	$ 282.5	$ 464.0	$ 136.8
Effective income tax rate	33.8%	39.5%	42.0%

Taxes other than income taxes consist of current and deferred petroleum revenue tax ("PRT"), other international taxes and provincial capital taxes. Taxes other than income taxes increased to $69.1 million or $0.53 per boe in 2001 from $49.5 million or $0.44 per boe in 2000 (1999 – $8.1 million or $0.11 per boe). The increase in other taxes was mainly due to the inclusion of a full year of production from the North Sea properties acquired in the Ranger acquisition. North Sea PRT accounts for $59.1 million or

$0.45 per boe in 2001 compared to $33.3 million or $0.29 per boe in 2000. PRT is charged on applicable fields at a rate of 50% of net operating income after certain deductions. New fields, including Banff and Kyle, are not subject to PRT.

Total current income tax expense in the North Sea is $61.8 million or $0.47 per boe. Net earnings in the North Sea are currently subject to a tax rate of 30%. Canadian Natural did not incur any cash Canadian federal income taxes in 2001. It is anticipated that, based on the current availability of $2.9 billion of tax pools in Canada at the end of 2001, the Company could be cash taxable in Canada in 2002 in the approximate range of $50 – $70 million. Canadian Natural is liable for the payment of federal Large Corporations Tax ("LCT"). LCT increased to $15.1 million or $0.11 per boe from $14.7 million or $0.13 per boe (1999 – $7.8 million, $0.10 per boe) due to an increase in Canadian Natural's capital base upon which the LCT is calculated.

Canadian Natural's future income tax provision for 2001 decreased to $282.5 million ($2.15 per boe) from $464.0 million ($4.14 per boe) in 2000 (1999 – $136.8 million or $1.80 per boe) due to the decrease in net earnings before tax. Canadian Natural's effective tax rate declined to 33.8% in 2001 from 39.5% in 2000 and 42.0% in 1999. A portion of the decrease is a result of the reductions in certain Canadian provinces' corporate income tax rates during 2001, resulting in a one-time reduction in the future income tax liability in the aggregate amount of $63.1 million. The effective tax rate is also reduced by the continuing benefit of the resource allowance on the Company's Canadian operations and lower income tax rates in the international segments.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	2001	2000	1999
Working capital deficit (surplus)	$ 5.6	$ 77.3	$ (36.4)
Long-term debt	2,669.2	2,454.5	2,156.8
Total	$ 2,674.8	$ 3,531.8	$ 2,120.4
Shareholders' equity			
Preferred securities	$ 118.3	$ 118.3	$ –
Share capital and contributed surplus	1,698.3	1,692.6	1,268.2
Retained earnings	1,979.5	1,406.0	623.8
Foreign currency translation adjustment	72.8	–	–
Total	$ 3,868.9	$ 3,216.9	$ 1,892.0
Debt to cash flow[1]	1.4x	1.3x	2.9x
Debt to book capitalization[1]	42.5%	45.4%	53.3%
Debt to market capitalization[1]	36.5%	32.6%	35.4%

[1] Includes preferred securities as debt equivalents.

Canadian Natural recognizes the need for a strong financial position in order to withstand volatile oil and natural gas commodity prices and the operational risks inherent in the oil and natural gas business environment.

Long-term debt at December 31, 2001, amounted to $2.7 billion and reflected a 1.4x debt to cash flow ratio and a debt to book capitalization of 42.5%, both reflecting our preferred securities as debt equivalents. These ratios are well within the Company's guidelines for balance sheet management.

During 2001, the Company successfully undertook to diversify its borrowing base through the filing of shelf prospectuses in Canada and the United States for the separate offering of up to $1 billion of medium-term notes in Canada and up to US $1 billion of debt securities in the United States. The securities, if and when issued, will be unsecured and will rank *pari passu* with other senior unsecured indebtedness of Canadian Natural.

In July 2001, the Company issued US $400 million of ten-year, 6.70% notes to purchasers in the United States under the shelf prospectus. In January 2002, the Company issued US $400 million of 30-year, 7.20% notes to purchasers in the United States. Net proceeds from both issuances were used to repay bank indebtedness. The securities were rated "Baa1" by Moody's Investors Service, Inc., "BBB+" by Standard & Poor's Corporation and "BBB (high)" by Dominion Bond Rating Service Limited. Future offerings under the shelf prospectuses will provide flexibility to the Company's debt investment base, extend maturities and provide balance in fixed/floating interest rate ratios.

Canadian Natural had unsecured bank credit facilities of approximately $1,840 million as at December 31, 2001 compared with $2,800 million at the close of 2000 (1999 – $2,250 million). During 2001, Canadian Natural cancelled three bank lines of credit aggregating approximately $1 billion. The Company's unutilized bank lines of credit currently exceed $900 million and are in addition to funds that are available through the Company's Canadian and United States shelf prospectuses. The facilities are reviewed annually and require no principal repayments provided certain covenants, including specific financial ratios, are maintained. Canadian Natural anticipates continuing to meet these requirements under its current operating forecast for 2002.

Share Capital

Canadian Natural issued 1.5 million common shares from the exercise of employee stock options and warrants throughout the year 2001 for proceeds of $45.5 million. In 2000, 3.2 million common shares from the exercise of employee stock options were issued for proceeds of $65.3 million and a further 7.6 million common shares were issued to acquire Ranger (1999 – 1.2 million common shares from the exercise of employee stock options for proceeds of $21.6 million).

The $118.3 million of preferred securities assumed on acquisition of Ranger represent equity under accounting principles generally accepted in Canada. Accordingly, the preferred securities dividend of $5.9 million net of tax ($10.3 million before tax) was recorded directly to retained earnings during the year (2000 – $2.8 million net of tax, $5.0 million before tax).

On January 17, 2001, the Company announced its intention to make a Normal Course Issuer Bid through the facilities of the Toronto Stock Exchange and the New York Stock Exchange to purchase up to 6,114,726 common shares or 5% of the outstanding common shares of the Company during the 12-month period beginning January 22, 2001 and ending January 21, 2002. As at December 31, 2001, the Company had purchased 2,537,800 common shares for a total cost of $113.3 million.

In January 2002, the Company renewed its Normal Course Issuer Bid, allowing the Company to purchase up to 6,060,180 common shares or 5% of the outstanding common shares of the Company during the 12-month period beginning January 23, 2002 and ending January 22, 2003.

On January 17, 2001, the Company announced the payment of a regular quarterly dividend of $0.10 per common share payable in January, April, July and October of each year. The initial payment was made on April 1, 2001 with the fourth payment made on January 1, 2002 to shareholders of record on December 14, 2001.

The Company declared dividends on common shares in the amount of $48.5 million ($0.40 per share) during the year ended December 31, 2001.

CAPITAL EXPENDITURES

($ millions)	2001	2000	1999
Acquisition of Ranger Oil Limited	$ –	$ 1,687.3	$ –
Expenditures on property, plant and equipment			
Net property acquisitions	$ 519.2	$ 150.2	$ 1,422.3
Land acquisition and retention	100.5	79.7	46.2
Seismic evaluations	94.6	40.5	17.9
Well drilling, completion and equipping	644.7	524.0	274.8
Pipeline and production facilities	395.0	335.7	143.2
Total net reserve replacement expenditures	1,754.0	1,130.1	1,904.4
Projects under construction	–	–	(6.5)
Midstream operations	97.3	–	–
Oil sands	26.8	–	–
Head office	6.4	5.9	2.7
Total net capital expenditures	$ 1,884.5	$ 1,136.0	$ 1,900.6
By segment			
North America	$ 1,582.8	$ 1,041.8	$ 1,900.6
North Sea	97.8	54.9	–
Offshore West Africa	203.9	39.3	–
Total	$ 1,884.5	$ 1,136.0	$ 1,900.6

The Company's strategy is focused on continuing to build a diversified asset base, which is balanced between heavy oil, light and Pelican Lake oil and natural gas. In 2001, the Company demonstrated the diversity and strength of its asset base by adjusting its capital expenditure budget to reflect changing economies and focused drilling on natural gas locations that resulted in the successful discovery at Ladyfern.

Capital expenditures totaled $1,884.5 million in the year 2001 compared to $1,136.0 million in 2000, excluding the corporate acquisition of Ranger (1999 – $1,900.6 million). Capital expenditures on North American properties accounted for 84% of expenditures, with the remainder expended in Canadian Natural's core operating regions in the North Sea and offshore West Africa. Well drilling, completion and equipping increased 23% over the prior year with the drilling of 1,092 net wells, compared to 813 net wells in 2000 (1999 – 727 net wells).

North American capital expenditures included the continuing development of the Ladyfern field where a total of seven wells were drilled and completed in 2001. The Company drilled fewer heavy oil wells and increased the number of natural gas wells that were drilled. Net property acquisitions included the acquisition of producing natural gas assets and undeveloped land in the Helmet area and the acquisition of additional producing and non-producing land interest in the Pelican Lake area. In addition, the Company disposed of a large portion of the United States assets acquired in the Ranger acquisition.

Capital expenditures also include the completion of phase one of the front-end engineering work for development of oil sands leases in the Horizon project. The Company's approach for this project is to extensively evaluate new technology options and predesign the infrastructure prior to construction. In this way, Canadian Natural will ensure cost certainty before significant activity begins. A strong staff of experts with experience in design, construction and operations in each of mining, extraction and upgrading has been assembled to lead this work. With respect to bitumen upgrading, Canadian Natural continues to evaluate various options, including both full and partial upgrading. The applications for project approval with regulatory authorities will be submitted in mid-2002. Canadian Natural continues to schedule the start of construction in 2004, with first synthetic oil production as early as 2007.

During 2001, the Company acquired the remaining 50% ownership interest in the ECHO Pipeline system and completed its planned extension. This pipeline, together with the Pelican Lake Pipeline (62% owned and operated) and the 15% ownership in the Cold Lake Pipeline, is part of the Company's focus to manage the development, and marketing of its heavy oil production. The midstream assets will allow the Company to transport its own production volumes at reduced operating costs as compared to other transportation alternatives as well as earn third party transportation revenue.

Internationally, capital expenditures include the drilling of the Canadian Natural operated Baobab 1X well in deep water offshore Côte d'Ivoire in West Africa. Oil was discovered in the lower Cretaceous sandstones and two drill stem tests on selected intervals tested in excess of 6,700 barrels of oil per day. A second successful well was drilled and tested at a rate in excess of 10,000 barrels of oil per day in the first quarter of 2002. In the second quarter of 2001, Canadian Natural increased its equity interest in its operated offshore Espoir field to 58.67% with the acquisition of one of its partner's equity interest. Canadian Natural continued the development of the Espoir field located offshore Côte d'Ivoire throughout 2001. This development included batch drilling of seven wells to an intermediate casing point from one wellhead tower, installation of a natural gas pipeline onshore from the field and in December, the arrival in the field of an FPSO vessel, the "Espoir Ivoirien". The FPSO has a processing capacity of 40,000 barrels of oil per day with a storage capacity of one million barrels. In February 2002, the first producing well completed drilling and was placed on production through the FPSO at an initial rate of 8,500 barrels of oil per day.

North Sea capital expenditures include tying in of the Kyle field in April 2001, the drilling of a third development well in the Kyle field and exploration in the Acorn/Beechnut field.

RISKS AND UNCERTAINTIES

Canadian Natural is exposed to several operational risks inherent in exploring, developing, producing and marketing of crude oil and natural gas. These inherent risks include: economic risk of finding and producing reserves at a reasonable cost; financial risk of marketing reserves at an acceptable price given market conditions; cost of capital risk associated with securing the needed capital to carry out the Company's operations; risk of fluctuating foreign exchange rates; risk of carrying out operations with minimal environmental impact; risk of governmental policies, social instability or other political, economic or diplomatic developments in its international operations; and credit risk of non-payment for sales contracts or non-performance by counter-parties to contracts.

Canadian Natural uses a variety of means to help minimize these risks. The Company maintains a comprehensive insurance program to reduce risk to an acceptable level and to protect it against significant losses. Operational control is enhanced by focusing efforts on large core areas with high working interests and by assuming operatorship of all key facilities. Product mix is diversified, ranging from the production of natural gas to the production of crude oil of various grades. Canadian Natural believes this diversification reduces price risk when compared with over leverage to one commodity. Marketing efforts are aimed at various markets to ensure that undue exposure to any one market does not exist. Financial instruments are utilized to help ensure targets are met and to manage commodity price, foreign currency and interest rate exposure. The Company minimizes credit risks by entering into sales contracts and financial derivatives with only highly rated entities and financial institutions. In addition, the Company reviews its exposure to individual companies on a regular basis, and where appropriate ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. Canadian Natural had a number of sales contracts in place with Enron Corp. and its subsidiaries during 2001, the final settlement of which is not expected to have a material impact on the Company's financial condition or results.

The Company's current position with respect to its financial instruments is detailed in note 11 of the Company's consolidated financial statements. The arrangements and policies concerning the Company's financial instruments are under constant review and may change depending upon the prevailing market conditions.

Canadian Natural's capital structure mix is also monitored on a continued basis to ensure that it optimizes flexibility, minimizes cost, and offers the greatest opportunity for growth. This includes the determination of a reasonable level of debt and any interest rate exposure risk that may exist.

Canadian Natural continues to employ an Environmental Management Plan to ensure the welfare of its employees, the communities in which it operates, and the environment as a whole. Environmental protection is of fundamental importance and is undertaken in accordance with guiding principles approved by the Company's Board of Directors. A detailed copy of the Company's Environmental Management Plan is presented to, and reviewed by, the Board of Directors annually. The Plan is updated quarterly at the Directors' meetings.

OUTLOOK

Canadian Natural has established a strong, balanced asset base. The asset base is comprised of conventional exploration and production operations, midstream assets and oil sands leases. The asset base provides growth opportunities in the short, medium and long-term. Based upon its $1.5 billion dollar capital budget in 2002, the Company expects to produce an average of 379,000 to 393,000 barrels of oil equivalent per day, a 7% increase over 2001 levels. This increase is comprised of natural gas production increases to between 1,075 and 1,125 million cubic feet per day (918 million cubic feet per day in 2001) and oil and liquids sales to average between 200 and 210 thousand barrels of oil per day (206 thousand barrels per day in 2001). Canadian Natural's 2002 capital expenditure program will be allocated approximately 79% to Canadian operations and 21% to international opportunities in the North Sea and offshore West Africa. It is anticipated that because of the Company's balanced asset base, the production mix for the year 2002 will be 19% light oil, 8% Pelican Lake oil, 25% heavy oil and 48% natural gas.

Canadian Natural's financial position is strong and we will continue to adhere to our long-term targets, ensuring our financial flexibility. In light of this, the Board of Directors announced that the annual dividend would increase 25% to $0.50 per common share payable quarterly, commencing with the April 1, 2002 payment. Furthermore, Canadian Natural extended for an additional 12-month period its Normal Course Issuer Bid through the facilities of the Toronto Stock Exchange and the New York Stock Exchange. The Bid allows for the purchase of up to 5% of the Company's common shares outstanding or 6,060,180 common shares during the 12-month period ending January 22, 2003.

SENSITIVITY ANALYSIS[1]

Annualized sensitivities to certain factors, which would influence the Company's financial results, are as follows:

	Cash flow from operations[2] *($ millions)*	Cash flow from operations[2] *(per share – basic)*	Net earnings[2] *($ millions)*	Net earnings[2] *(per share – basic)*
Price changes				
Oil – WTI US $1.00/bbl[3]				
Excluding financial derivatives	$98	$0.80	$69	$0.57
Including financial derivatives	$74 – $98	$0.61 – $0.80	$52 – $69	$0.43 – $0.57
Natural gas – Cdn $1.00/mcf[3]				
Excluding financial derivatives	$285	$2.35	$174	$1.43
Including financial derivatives	$231 – $267	$1.90 – $2.20	$141 – $163	$1.16 – $1.34
Volume changes				
Oil – 10,000 bbls/d	$36	$0.30	$6	$0.05
Natural gas – 10 mmcf/d	$7	$0.05	$1	$0.01
Foreign currency rate change				
$0.01 increase in Cdn $ in relation to US $[3]				
Excluding financial derivatives	$30	$0.25	$18	$0.15
Including financial derivatives	$24 – $28	$0.20 – $0.23	$15 – $17	$0.12 – $0.14
Interest rate change – 1%	$20	$0.16	$12	$0.10

(1) The sensitivities are calculated based on 2001 fourth quarter results.

(2) Attributable to common shareholders.

(3) For details of financial derivatives in place, see financial statement note 11.

Daily Production By Segment

	Q4	Q3	Q2	Q1	2001	**2000**	**1999**
Oil and liquids *(bbls/d)*							
North America	159,000	162,890	168,938	176,102	166,675	154,331	86,750
North Sea	35,749	40,356	41,556	27,210	36,252	17,195	–
Offshore West Africa	3,251	3,819	4,222	2,276	3,396	2,065	–
Total	198,000	207,065	214,716	205,588	206,323	173,591	86,750
Natural gas *(mmcf/d)*							
North America	993	906	873	851	906	793	721
North Sea	19	18	12	–	12	1	–
Total	1,012	924	885	851	918	794	721
Barrels of oil equivalent *(boe/d)*							
North America	324,490	313,838	314,377	317,896	317,658	286,476	206,922
North Sea	38,853	43,372	43,555	27,210	38,293	17,446	–
Offshore West Africa	3,251	3,819	4,222	2,276	3,396	2,065	–
Total	366,594	361,029	362,154	347,382	359,347	305,987	206,922

Per Unit Results

	Q4	Q3	Q2	Q1	2001	**2000**	**1999**
Oil and liquids *($/bbl)*							
Sales price	$ 21.28	$ 28.37	$ 25.32	$ 22.06	$ 24.31	$ 29.99	$ 21.04
Royalties	1.41	2.47	2.42	2.36	2.17	3.05	2.25
Production expense	7.41	7.10	7.32	7.88	7.42	6.38	4.90
Netback	$ 12.46	$ 18.80	$ 15.58	$ 11.82	$ 14.72	$ 20.56	$ 13.89
Natural gas *($/mcf)*							
Sales price	$ 2.94	$ 3.12	$ 5.93	$ 9.30	$ 5.16	$ 4.53	$ 2.36
Royalties	0.62	0.67	1.47	2.40	1.25	1.08	0.44
Production expense	0.53	0.50	0.50	0.50	0.51	0.44	0.37
Netback	$ 1.79	$ 1.95	$ 3.96	$ 6.40	$ 3.40	$ 3.01	$ 1.55
Barrels of oil equivalent *($/boe)*							
Sales price	$ 19.62	$ 24.25	$ 29.54	$ 35.85	$ 27.15	$ 28.77	$ 17.03
Royalties	2.47	3.14	5.03	7.27	4.42	4.51	2.49
Production expense	5.47	5.36	5.57	5.89	5.57	4.76	3.34
Netback	$ 11.68	$ 15.75	$ 18.94	$ 22.69	$ 17.16	$ 19.50	$ 11.20

Netback Analysis

($/boe, except daily production)	2001	**2000**	**1999**
Daily production *(boe)*	359,347	305,987	206,922
Sales price	$ 27.15	$ 28.77	$ 17.03
Royalties	4.42	4.51	2.49
Production expense	5.57	4.76	3.34
Netback	17.16	19.50	11.20
Administration	0.29	0.25	0.23
Interest	1.05	1.45	1.19
Foreign exchange (gain) loss	(0.01)	–	0.01
Taxes other than income tax (current)	0.53	0.51	0.11
Current income tax (North Sea)	0.47	0.30	–
Current income tax (Large Corporations Tax)	0.11	0.13	0.10
Cash flow	14.72	16.86	9.56
Depletion, depreciation and amortization	6.89	5.75	5.08
Loss on sale of United States assets	0.19	–	–
Unrealized foreign exchange loss	0.12	0.03	0.03
Taxes other than income tax (deferred)	–	(0.07)	–
Future income taxes	2.15	4.14	1.80
Net earnings	5.37	7.01	2.65
Dividend on preferred securities	0.04	0.03	–
Net earnings attributable to common shareholders	$ 5.33	$ 6.98	$ 2.65

Quarterly Financial Information

($ millions, except per share amounts)	Q4	Q3	Q2	Q1	Total
2001					
Oil and natural gas revenue	$ 661.5	$ 805.5	$ 973.5	$ 1,120.9	$ 3,561.4
Cash flow from operations attributable to					
common shareholders	$ 325.7	$ 437.4	$ 527.6	$ 629.3	$ 1,920.0
Per share – basic	$ 2.69	$ 3.63	$ 4.36	$ 5.15	$ 15.83
– diluted	$ 2.63	$ 3.50	$ 4.18	$ 4.94	$ 15.25
Net earnings attributable to					
common shareholders	$ 52.0	$ 132.3	$ 249.4	$ 264.5	$ 698.2
Per share – basic	$ 0.43	$ 1.10	$ 2.06	$ 2.17	$ 5.76
– diluted	$ 0.43	$ 1.08	$ 1.97	$ 2.08	$ 5.56
2000					
Oil and natural gas revenue	$ 1,030.9	$ 1,003.8	$ 637.4	$ 550.4	$ 3,222.5
Cash flow from operations attributable to					
common shareholders	$ 552.7	$ 587.4	$ 400.3	$ 343.2	$ 1,883.6
Per share – basic	$ 4.56	$ 4.97	$ 3.55	$ 3.06	$ 16.14
– diluted	$ 4.39	$ 4.80	$ 3.44	$ 3.01	$ 15.64
Net earnings attributable to					
common shareholders	$ 223.2	$ 241.2	$ 175.5	$ 142.3	$ 782.2
Per share – basic	$ 1.84	$ 2.04	$ 1.55	$ 1.27	$ 6.70
– diluted	$ 1.77	$ 1.97	$ 1.51	$ 1.25	$ 6.50

Trading and Share Statistics

	Q4	Q3	Q2	Q1	2001 Total	**2000 Total**
TSE – CDN $						
Trading volume *(thousands)*	34,513	24,564	37,512	37,155	133,744	141,853
Share price *($/share)*						
High	$ 45.25	$ 49.49	$ 52.35	$ 50.30	$ 52.35	$ 56.20
Low	$ 35.90	$ 37.65	$ 42.90	$ 39.35	$ 35.90	$ 29.80
Close	$ 38.31	$ 38.76	$ 44.85	$ 45.65	$ 38.31	$ 41.50
Market capitalization at						
December 31 *($ millions)*					$ 4,643	$ 5,075
Shares outstanding *(thousands)*					121,201	122,279
NYSE – US $						
Trading volume *(thousands)*	1,504	1,054	1,855	778	5,191	793
Share price *($/share)*						
High	$ 28.80	$ 32.25	$ 34.51	$ 32.45	$ 34.51	$ 37.81
Low	$ 22.80	$ 23.96	$ 27.85	$ 26.38	$ 22.80	$ 24.75
Close	$ 24.40	$ 24.34	$ 29.65	$ 28.85	$ 24.40	$ 27.50
Market capitalization at						
December 31 *($ millions)*					$ 2,957	$ 3,363
Common shares						
outstanding *(thousands)*					121,201	122,279

management's report

The accompanying consolidated financial statements and all information in the annual report are the responsibility of management. The consolidated financial statements have been prepared by management in accordance with the accounting policies in the notes to the consolidated financial statements. Where necessary, management has made informed judgements and estimates in accounting for transactions which were not complete at the balance sheet date. In the opinion of management, the financial statements have been prepared within acceptable limits of materiality and are in accordance with Canadian generally accepted accounting principles appropriate in the circumstances. The financial information elsewhere in the annual report has been reviewed to ensure consistency with that in the consolidated financial statements.

Management maintains appropriate systems of internal control. Policies and procedures are designed to give reasonable assurance that transactions are appropriately authorized, assets are safeguarded from loss or unauthorized use and financial records are properly maintained to provide reliable information for preparation of financial statements.

PricewaterhouseCoopers LLP, an independent firm of Chartered Accountants, has been engaged, as approved by a vote of the shareholders at the Company's most recent Annual General Meeting, to examine the consolidated financial statements in accordance with generally accepted auditing standards in Canada and provide an independent professional opinion. Their report is presented with the consolidated financial statements.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility through the Audit Committee of the Board. This committee, which is comprised of a majority of non-management directors, meets with management and the external auditors to satisfy itself that management responsibilities are properly discharged and to review the consolidated financial statements before they are presented to the Board of Directors for approval. The consolidated financial statements have been approved by the Board of Directors on the recommendation of the Audit Committee.

John G. Langille, CA
President and Director
February 26, 2002

Douglas A. Proll, CA
Vice-President, Finance

Randall Davis

Randall S. Davis, CA
Manager, Financial Accounting

auditors' report to the shareholders

We have audited the consolidated balance sheets of Canadian Natural Resources Limited as at December 31, 2001 and 2000 and the consolidated statements of earnings, retained earnings and cash flows for each of the years in the three year period ended December 31, 2001. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2001 and 2000 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2001 in accordance with accounting principles generally accepted in Canada.

PricewaterhouseCoopers LLP

Calgary, Alberta
February 26, 2002

PricewaterhouseCoopers LLP
Chartered Accountants

consolidated balance sheets

As at December 31 *(millions of Canadian dollars)*	2001	2000
ASSETS		
Current assets		
Cash	$ 15.0	$ 28.0
Accounts receivable and other	509.0	584.0
	524.0	612.0
Property, plant and equipment (note 3)	8,442.9	7,141.5
Deferred charges (note 4)	73.8	22.1
	9,040.7	7,775.6
LIABILITIES		
Current liabilities		
Accounts payable	249.5	301.1
Accrued liabilities	264.2	371.7
Current portion of long-term debt (note 5)	15.9	16.5
	529.6	689.3
Long-term debt (note 5)	2,669.2	2,454.5
Future site restoration (note 6)	193.8	170.5
Future income tax (note 7)	1,779.2	1,244.4
	5,171.8	4,558.7
SHAREHOLDERS' EQUITY		
Preferred securities (note 8)	118.3	118.3
Share capital and contributed surplus (note 9)	1,698.3	1,692.6
Retained earnings	1,979.5	1,406.0
Foreign currency translation adjustment (note 1)	72.8	–
	3,868.9	3,216.9
	$ 9,040.7	$ 7,775.6

Signed on behalf of the Board

James S. Palmer
Chairman of the Audit Committee and Director

N. Murray Edwards
Director

consolidated statements of earnings

For the Years Ended December 31 *(millions of Canadian dollars, except per share amounts)*	2001	2000	1999
Revenue			
Oil and natural gas	$ 3,561.4	$ 3,222.5	$ 1,286.8
Less: royalties	(580.3)	(506.2)	(187.9)
	2,981.1	2,716.3	1,098.9
Expenses			
Production	730.5	532.9	252.0
Depletion, depreciation and amortization	903.8	644.6	384.3
Administration	37.6	27.2	17.0
Interest	137.8	162.3	90.1
Foreign exchange loss	14.7	2.4	2.6
Loss on sale of United States assets (note 3)	24.1	–	–
	1,848.5	1,369.4	746.0
Earnings Before Taxes	1,132.6	1,346.9	352.9
Taxes other than income tax (note 7)	69.1	49.5	8.1
Current income tax (note 7)	76.9	48.4	7.8
Future income tax (note 7)	282.5	464.0	136.8
Net Earnings	704.1	785.0	200.2
Dividend on preferred securities (net of tax)	(5.9)	(2.8)	–
Net Earnings Attributable to Common Shareholders	$ 698.2	$ 782.2	$ 200.2
Net earnings per common share attributable to common shareholders (notes 2 and 10)			
Basic	$ 5.70	$ 6.70	$ 1.93
Diluted	$ 5.56	$ 6.50	$ 1.90

consolidated statements of retained earnings

For the Years Ended December 31 *(millions of Canadian dollars)*	2001	2000	1999
Retained Earnings – Beginning of Year	$ 1,406.0	$ 623.8	$ 423.6
Net earnings	704.1	785.0	200.2
Purchase of common shares (note 9)	(76.2)	–	–
Dividend on common shares (note 9)	(48.5)	–	–
Dividend on preferred securities (net of tax)	(5.9)	(2.8)	–
Retained Earnings – End of Year	$ 1,979.5	$ 1,406.0	$ 623.8

consolidated statements of cash flows

For the Years Ended December 31 *(millions of Canadian dollars)*	2001	2000	1999
Operating Activities			
Net earnings	$ 704.1	$ 785.0	$ 200.2
Non-cash items			
Depletion, depreciation and amortization	903.8	644.6	384.3
Loss on sale of United States assets	24.1	–	–
Deferred petroleum revenue tax (recovery)	(0.2)	(7.6)	–
Future income tax	282.5	464.0	136.8
Unrealized foreign exchange loss	16.0	2.6	2.2
Cash flows provided from operations	1,930.3	1,888.6	723.5
Net change in non-cash working capital	(42.2)	(55.4)	(54.7)
	1,888.1	1,833.2	668.8
Financing Activities			
(Repayment) increase of bank credit facilities	(442.3)	(187.7)	623.5
Repayment of limited recourse loan	(11.8)	(0.7)	–
Repayment of senior unsecured notes	(15.8)	(15.1)	–
Issue of US debt securities	615.2	–	–
Issue of medium-term notes	–	125.0	125.0
Issue of common shares	42.8	66.4	404.3
Purchase of common shares	(113.3)	–	–
Dividend on common shares	(36.4)	–	–
Dividend on preferred securities	(10.3)	(5.0)	–
Net change in non-cash working capital	7.4	5.8	0.1
	35.5	(11.3)	1,152.9
Investing Activities			
Expenditures on property, plant and equipment	(1,947.5)	(1,294.6)	(1,923.7)
Corporate acquisition (note 12)	–	(722.8)	–
Net proceeds on sale of property, plant and equipment	63.0	160.3	26.0
Net expenditures on property, plant and equipment	(1,884.5)	(1,857.1)	(1,897.7)
Net change in non-cash working capital	(52.1)	63.1	76.0
	(1,936.6)	(1,794.0)	(1,821.7)
(Decrease) Increase in Cash	(13.0)	27.9	–
Cash – Beginning of Year	28.0	0.1	0.1
Cash – End of Year	$ 15.0	$ 28.0	$ 0.1
Supplemental disclosure of cash flow information			
Interest paid	$ 127.4	$ 169.3	$ 90.0
Taxes paid	$ 161.2	$ 62.3	$ 14.3

1 ACCOUNTING POLICIES

The consolidated financial statements of Canadian Natural Resources Limited (the "Company") have been prepared in accordance with accounting principles generally accepted in Canada. Management has made estimates and assumptions regarding certain assets, liabilities, revenues and expenses in the preparation of the financial statements. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements. Accordingly, actual results may differ from estimated amounts. Significant accounting policies are summarized as follows:

Principles of consolidation

The consolidated financial statements include the accounts of the Company and all of its subsidiaries and partnerships. A portion of the Company's activity is conducted jointly with others and the consolidated financial statements reflect only the Company's proportionate interest in such activities.

Cash and cash equivalents

Cash comprises cash on hand and demand deposits. Other investments (term deposits and certificates of deposit) purchased with a maturity date of three months or less are reported as cash equivalents.

Property, plant and equipment

The Company follows the full cost method of accounting for petroleum and natural gas properties and equipment as prescribed by the Canadian Institute of Chartered Accountants ("CICA") whereby all costs relating to the exploration for and development of oil and natural gas reserves are capitalized and accumulated in country-by-country cost centres. Proceeds on disposal of properties are ordinarily deducted from such costs without recognition of profit or loss except where such disposal constitutes a significant portion of the Company's reserves in that country.

The costs related to each cost centre from which there is production are depleted on the unit-of-production method based on the estimated proved reserves of each country. Volumes of net production and net reserves before royalties are converted to equivalent units on the basis of estimated relative energy content. In determining its depletion base, the Company includes estimated future costs to be incurred in developing proved reserves and excludes the cost of unproved properties. The unproved properties are assessed periodically to ascertain whether impairment has occurred. When proved reserves are assigned or the value of the unproved property is considered to be impaired, the cost of the unproved property or the amount of the impairment is added to costs subject to depletion. Certain costs in cost centres from which there has been no commercial production are not subject to depletion until commercial production commences.

Processing and production facilities ("facilities"), net of salvage value, are depreciated based on their estimated useful life of 20 years.

The Company carries its petroleum and natural gas properties at the lower of the capitalized cost and net recoverable value (the "ceiling test"). The net capitalized cost of each cost centre is calculated as the net book value of the related assets less the accumulated provisions for future income taxes and future site restoration. Net recoverable value is limited to the sum of future net revenues from proved properties and the cost of unproved properties net of provisions for impairment less estimated future financing and administrative expenses and income taxes. Future net revenues are based on prices and costs prevailing at year end.

Future site restoration

Estimated future dismantlement, site restoration and abandonment costs of petroleum and natural gas properties are provided for using the unit-of-production method. Facilities are provided for using the straight-line method over the estimated useful life of the assets of 20 years. Expenditures incurred to dismantle facilities and restore well sites are charged against the related restoration liability.

Depreciation and amortization of other capital assets

Other capital assets are amortized on a declining balance basis over their estimated useful life of five years.

Foreign currency translation

Effective October 1, 2001, the Company determined that as a result of a change in the management structure for its international operations, operations in the North Sea were now operationally and financially independent and the current rate method of translation was adopted for translation of the financial statements of the North Sea subsidiaries. Under this method, assets and liabilities are translated to Canadian dollars from their functional currency using the exchange rate in effect at the balance sheet date. Revenues and expenses are translated to Canadian dollars at the monthly average exchange rate. Gains or losses on translation are included in the foreign currency translation adjustment in shareholders' equity in the consolidated balance sheets. This change has been applied prospectively. Had the change not been adopted, assets and liabilities of the Company as at December 31, 2001, would have been $8,957.9 million and $5,164.2 million, respectively and net earnings for the Company for the year ended December 31, 2001, would have been $701.7 million.

Operations that are not considered to be self-sustaining are translated using the temporal method. For foreign currency balances and integrated subsidiaries, monetary assets and liabilities are translated to Canadian dollars at the exchange rate in effect at the balance sheet date and non-monetary assets and liabilities are translated at the rate of exchange in effect when the assets are acquired or obligations incurred. Revenues and expenses are translated to Canadian dollars at the monthly average exchange rate. Provisions for depletion, depreciation and future site restoration are translated at the same rate as the related items. Preferred securities are not revalued for changes in the exchange rate as they are considered to be equity of the Company.

Petroleum revenue tax

The Company accounts for future United Kingdom petroleum revenue tax ("PRT") by the life-of-the-field method. The total future liability or recovery of PRT is estimated using current prices and costs. The estimated future PRT is apportioned to accounting periods on the basis of estimated future revenues. Changes in the estimated total future PRT are accounted for prospectively.

Income tax

The Company follows the liability method of accounting for income taxes. Under this method, income tax assets and liabilities are recognized based on the estimated tax effects of temporary differences in the carrying value of assets and liabilities in the financial statements and their respective tax bases, using income tax rates substantially enacted on the balance sheet date. The effect of a change in income tax rates on the future income tax assets and liabilities is recognized in income in the period of the change.

Stock-based compensation plans

Consideration paid by employees or directors on the exercise of stock options under the employee stock option plan is recorded as share capital. No compensation expense is recorded either on granting or exercise of options under the plan. The Company matches employee contributions to the stock savings plan and these cash payments are recorded as compensation expense.

Financial instruments

The Company uses various financial instruments to reduce its exposure to commodity price and foreign exchange rate fluctuations. The Company does not use these instruments for trading purposes. Gains or losses on these contracts are included in oil and natural gas revenue at the time of sale of the related product. The Company also uses financial instruments to manage its interest rate exposure. Gains or losses on these contracts are included in interest expense.

2 CHANGE IN ACCOUNTING POLICIES

Earnings per share

Effective January 1, 2001, the Company adopted the CICA's new accounting standard with respect to the calculation and presentation of per share amounts. Under the new standard, the treasury stock method of calculating per share amounts is used whereby any proceeds from the exercise of stock options or other dilutive instruments are assumed to be used to purchase common shares at the average market price during the period. The new standard has been applied retroactively and prior periods have been restated. The new standard has no effect on basic per share and diluted per share amounts.

3 PROPERTY, PLANT AND EQUIPMENT

	2001		
	Cost	Accumulated depletion and depreciation	Net
Oil and natural gas			
North America	$ 9,778.9	$ 2,627.9	$ 7,151.0
North Sea	1,050.3	184.7	865.6
Offshore West Africa	425.2	15.3	409.9
Other	32.3	15.9	16.4
	$ 11,286.7	$ 2,843.8	$ 8,442.9

	2000		
	Cost	Accumulated depletion and depreciation	Net
Oil and natural gas			
North America	$ 8,010.6	$ 1,918.8	$ 6,091.8
North Sea	868.3	52.3	816.0
Offshore West Africa	221.3	0.9	220.4
Other	24.6	11.3	13.3
	$ 9,124.8	$ 1,983.3	$ 7,141.5

North American oil and natural gas asset expenditures for 2001 include a $190.4 million future tax addition (2000 – $76.6 million future tax recovery) on the purchase and sale of assets with a tax basis that differs from the purchase and sale price. During the year ended December 31, 2001, the Company capitalized administrative overhead of $6.7 million (2000 – $3.7 million; 1999 – $nil) relating to exploration and development in the North Sea and offshore West Africa. Costs of $1,032.9 million (2000 – $714.1 million; 1999 – $418.1 million) relating to unproved land and pre-commercial operations have been excluded from the Company's depletion base. During the year, the Company sold a large portion of its properties in the United States and recorded a loss on sale of $24.1 million.

The Company has never had a writedown of property, plant and equipment under the ceiling test.

4 DEFERRED CHARGES

	2001	2000
Unrealized foreign exchange loss	$ 61.9	$ 13.8
Deferred petroleum revenue tax	11.9	8.3
	$ 73.8	$ 22.1

5 LONG-TERM DEBT

	Pro forma January 1, 2002[1]	2001	2000
Bank credit facilities			
Bankers' acceptances	$ 678.5	$ 1,003.4	$ 1,445.7
US $ Bankers' acceptances (US $196 million)	–	312.1	294.0
US $ LIBOR advances (US $100 million)	159.3	159.3	150.0
Limited recourse loan	–	–	11.8
Medium term notes			
6.85% unsecured debentures due May 28, 2004	125.0	125.0	125.0
7.40% unsecured debentures due March 1, 2007	125.0	125.0	125.0
US debt securities			
6.70% due July 15, 2011 (US $400 million)	637.0	637.0	–
7.20% due January 15, 2032 (US $400 million)	637.0	–	–
Senior unsecured notes			
6.95% due September 30, 2003 (US $20 million, 2000 – US $30 million)	31.9	31.9	45.0
6.42% due May 27, 2004 (US $40 million)	63.7	63.7	60.0
6.50% due May 1, 2008 (US $50 million)	79.6	79.6	75.0
Adjustable rate due May 27, 2009 (US $93 million)	148.1	148.1	139.5
	2,685.1	2,685.1	2,471.0
Current portion of long-term debt	(15.9)	(15.9)	(16.5)
	$ 2,669.2	$ 2,669.2	$ 2,454.5

[1] On January 23, 2002, the Company issued US $400 million of debt securities. The pro forma gives effect to the proceeds and their initial use.

Bank credit facilities
The Company has unsecured bank credit facilities of approximately $1,840 million comprised of a $100 million operating demand facility, a revolving credit and term loan facility totaling $1,500 million and a revolving credit and term loan facility of US $150 million. The Canadian revolving credit and term loan facility is fully revolving for 364-day periods with a provision for extension at the mutual agreement of the Company and the lenders. If not extended, the facility converts to a non-revolving reducing loan with a term of four years. Principal payments during the term period amortize on the basis of one-fourth of the outstanding principal being due 12 months after the initiation of the term period followed by 12 equal quarterly payments thereafter. The facility provides that the borrowings may be made by way of operating advance, prime loans, bankers' acceptances, US base rate loans or US dollar LIBOR advances which bear interest at the bank's prime rates or at money market rates plus applicable margins. The US $150 million credit facility provides for LIBOR advances bearing interest at market rates plus applicable margins and is fully revolving for a 364-day period with a provision for extension by mutual agreement of the lenders and the Company. If not extended, the facility converts into a non-revolving reducing loan with a one-year term, with the principal amount payable at the end of the term. During the year, the Company repaid and cancelled two credit facilities totaling $975 million as well as the limited recourse loan.

In addition to the outstanding debt, letters of credit aggregating $30.2 million have been issued.

Medium-term notes
In July 2001, the Company authorized a new medium-term notes program in the aggregate principal amount of up to $1 billion for issue in Canada. The notes bear interest as determined at the date of issuance. No amounts are currently drawn under this program. The Company has $250 million of medium-term notes outstanding from a previous medium-term notes program.

US debt securities
In July 2001, the Company authorized a US debt securities program in the aggregate principal amount of up to US $1 billion for issue in the United States. The notes bear interest as determined at the date of issuance. On July 24, 2001, the Company issued US $400 million of US debt securities, maturing July 15, 2011, bearing interest at 6.70%. In August 2001, the Company entered into interest rate swap contracts that convert the fixed rate interest coupon into a floating interest rate for a portion of the term (note 11).

On January 23, 2002, the Company issued US $400 million of US debt securities maturing January 15, 2032, bearing interest at 7.20%. Proceeds from the notes issued were used to repay bankers' acceptances under the Company's bank credit facilities, including the US $196 million bankers' acceptances. The Company subsequently entered into interest rate swap contracts that convert the fixed rate interest coupon into a floating interest rate for a portion of the term (note 11).

Senior unsecured notes
The 6.95% notes due September 30, 2003, have principal repayments of US $10.0 million on September 30, 2002 and September 30, 2003. The 6.42% notes are due in full May 27, 2004. Annual principal repayments of US $10.0 million on the 6.50% notes commence May 1, 2004, through May 1, 2008. The adjustable rate notes bear interest at 6.54% increasing to 6.64% under certain circumstances, and have annual principal repayments of US $31.0 million commencing on May 27, 2007, through May 27, 2009. The debt instruments contain covenants pertaining to the Company's net worth, certain financial ratios and the ability to grant security. At December 31, 2001, the Company is in compliance with all covenants.

Required debt repayments
Required debt repayments are as follows:

Year	Repayment
2002	$ 15.9
2003	$ 15.9
2004	$ 204.6
2005	$ 15.9
2006	$ 15.9
Thereafter	$ 942.1

No debt repayments are reflected for the bank credit facilities due to the extendable nature of the facilities.

6 FUTURE SITE RESTORATION

	2001	2000
Balance – beginning of year	$ 170.5	$ 36.9
Site restoration provision	34.1	19.4
Current year expenditures	(9.5)	(15.1)
Acquisitions and dispositions	(1.3)	129.3
Balance – end of year	$ 193.8	$ 170.5

At December 31, 2001, the Company's total estimated future site restoration costs, without taking into account salvage values, were $1,081.0 million (2000 – $874.3 million). These costs will be accrued over the life of the Company's proved reserves.

7 TAXES

Taxes other than income tax

	2001	2000	1999
Current petroleum revenue tax	$ 59.3	$ 40.9	$ –
Deferred petroleum revenue tax (recovery)	(0.2)	(7.6)	–
Provincial capital taxes and surcharges	8.5	12.3	8.1
Other	1.5	3.9	–
	$ 69.1	$ 49.5	$ 8.1

The measurement of petroleum revenue tax expense and the related provision in the consolidated financial statements are subject to uncertainty associated with future recoverability of oil and natural gas reserves, commodity prices and the timing of future events, which could result in material changes to deferred amounts.

Income tax

The provision for income tax is as follows:

	2001	2000	1999
Current income tax expense			
Current income tax – North Sea	$ 61.8	$ 33.7	$ –
Large Corporations Tax – North America	15.1	14.7	7.8
	76.9	48.4	7.8
Future income tax expense	282.5	464.0	136.8
	$ 359.4	$ 512.4	$ 144.6

The provision for income taxes is different from the amount computed by applying the combined statutory Canadian federal and provincial income tax rates to earnings before taxes. The reasons for the difference are as follows:

	2001	2000	1999
	42.8%	*44.0%*	*44.0%*
Income tax provision at statutory rate	$ 484.8	$ 592.6	$ 155.3
Effect on taxes of:			
Non-deductibility of crown royalties, lease rentals and mineral taxes	201.1	193.2	64.8
Resource allowance	(219.5)	(238.1)	(95.7)
Large Corporations Tax	15.1	14.7	7.8
Deductible petroleum revenue tax	(25.3)	(14.6)	–
Foreign tax rate differentials	(18.9)	(40.9)	–
Provincial income tax rate reductions	(63.1)	–	–
Other	(14.8)	5.5	(0.6)
Non-tax base depletion	–	–	13.0
	$ 359.4	$ 512.4	$ 144.6

The following table summarizes the temporary differences that give rise to the future income tax liability:

	2001	2000
Future income tax liabilities		
Property, plant and equipment	$ 1,384.8	$ 1,052.4
Timing of partnership items	493.2	479.5
Other	5.0	5.0
Future income tax assets		
Future site restoration	(54.1)	(49.0)
Attributed Canadian Royalty Income	(39.8)	(36.7)
Non-capital income tax losses	–	(180.5)
Other	(9.9)	(26.3)
Future income tax liability	$ 1,779.2	$ 1,244.4

8 PREFERRED SECURITIES

The US $80 million preferred securities are in the form of 8.30% subordinated notes. Principal repayments of US $26.7 million are required annually commencing June 25, 2009. The securities may be prepaid at the option of the Company at any time. The prepaid amount is subject to certain adjustments to compensate holders for any potential loss of return over the original life of the securities, based on market conditions at that time. The notes are subordinated to the long-term debt of the Company and contain, among other things, certain financial covenants restricting the granting of security for new borrowings and the maintenance of specified financial ratios. As at December 31, 2001, the Company is in compliance with all covenants.

The Company has the unrestricted right to pay dividends, principal and principal prepayment amounts by delivering common shares to the Trustee of the preferred securities. The semi-annual dividend payments may be deferred at the option of the Company for up to two consecutive periods, with a maximum of eight deferral periods over the life of the securities.

9 SHARE CAPITAL AND CONTRIBUTED SURPLUS

Authorized

200,000 Class 1 preferred shares with a stated value of $10 each. Unlimited number of common shares without par value.

Share capital and contributed surplus

	2001	2000
Common shares	$ 1,698.3	$ 1,688.0
Warrants	–	2.7
Contributed surplus	–	1.9
	$ 1,698.3	$ 1,692.6

Issued

	2001		2000	
	Number of shares *(thousands)*	Amount	Number of shares *(thousands)*	Amount
Common shares				
Balance – beginning of year	122,279	$ 1,688.0	111,454	$ 1,263.4
Issued for acquisition of Ranger	–	–	7,602	358.0
Exercise of stock options	1,005	29.2	3,188	65.3
Exercise of warrants	455	16.3	35	1.3
Purchase of shares under Normal Course Issuer Bid	(2,538)	(35.2)	–	–
Balance – end of year	121,201	$ 1,698.3	122,279	$ 1,688.0

	2001		2000	
	Number of warrants *(thousands)*	Amount	Number of warrants *(thousands)*	Amount
Warrants				
Balance – beginning of year	465	$ 2.7	500	$ 2.9
Exercised during the year	(455)	(2.7)	(35)	(0.2)
Expired during the year	(10)	–	–	–
Balance – end of year	–	$ –	465	$ 2.7

Contributed surplus

	2001	2000
Balance – beginning of year	$ 1.9	$ 1.9
Purchase of shares under Normal Course Issuer Bid	(1.9)	–
Balance – end of year	$ –	$ 1.9

Normal Course Issuer Bid

On January 17, 2001, the Company announced its intention to make a Normal Course Issuer Bid through the facilities of the Toronto Stock Exchange and the New York Stock Exchange to purchase up to 6,114,726 common shares or 5% of the outstanding common shares of the Company on the date of announcement during the 12-month period beginning January 22, 2001, and ending January 21, 2002. As at December 31, 2001, the Company had purchased 2,537,800 common shares for a total cost of $113.3 million. The excess cost over book value of the shares purchased was applied to contributed surplus and retained earnings.

In January 2002, the Company renewed its Normal Course Issuer Bid, allowing the Company to purchase up to 6,060,180 common shares or 5% of the Company's outstanding common shares on the date of announcement, during the 12-month period beginning January 23, 2002 and ending January 22, 2003.

Dividend policy

On January 17, 2001, the Company announced the payment of a regular quarterly dividend of $0.10 per common share payable in January, April, July and October of each year.

Warrants

During 1999, the Company issued 500,000 warrants at an ascribed value of $2.9 million to acquire property, plant and equipment. Each warrant entitled the holder to acquire one common share of the Company at a price of $30 per common share until August 16, 2001.

Stock options

The Company's stock option plan provides for granting of options to certain directors, officers and employees. Options granted under the plan have a maximum term of six years to expiry and vest equally over a five-year period starting on the first anniversary date of the grant. The exercise price of each option granted equals the market price of the Company's common shares on the date of grant.

The following table summarizes the information relating to stock options outstanding at December 31, 2001, and 2000:

	2001		2000	
	Stock options *(thousands)*	**Weighted average exercise price**	**Stock options** *(thousands)*	**Weighted average exercise price**
Outstanding – beginning of year	10,664	$ 32.78	9,664	$ 25.99
Granted	3,500	$ 40.85	5,202	$ 39.18
Exercised	(1,005)	$ 29.12	(3,188)	$ 20.48
Forfeited	(1,108)	$ 39.89	(1,014)	$ 39.61
Outstanding – end of year	12,051	$ 34.77	10,664	$ 32.78
Exercisable – end of year	3,615	$ 31.42	2,235	$ 29.80

The range of exercise prices of stock options outstanding and exercisable at December 31, 2001, is as follows:

	Options outstanding			Options exercisable	
Range of exercise prices	**Options outstanding** *(thousands)*	**Weighted average remaining term** *(years)*	**Weighted average exercise price**	**Options exercisable** *(thousands)*	**Weighted average exercise price**
$19.88 to $24.99	1,473	2.6	$ 22.23	760	$ 22.41
$25.00 to $29.99	1,403	2.1	$ 27.10	658	$ 27.20
$30.00 to $34.99	4,160	3.1	$ 33.81	1,729	$ 34.10
$35.00 to $39.99	3,050	4.9	$ 39.35	171	$ 38.33
$40.00 to $48.10	1,965	4.8	$ 44.57	297	$ 44.32
	12,051	3.7	$ 34.77	3,615	$ 31.42

Stock-based compensation

The Company accounts for its stock-based compensation using the intrinsic value method, whereby no compensation costs have been recorded in the financial statements for share options granted. Had the Company adopted the fair value based method of accounting, the compensation costs, along with the pro forma net earnings and pro forma net earnings per share for the Company would be as follows:

	2001	2000
Stock-based compensation costs	$ 18.8	$ 8.5
Net earnings attributable to common shareholders		
As reported	$ 698.2	$ 782.2
Pro forma	$ 679.4	$ 773.7
Net earnings per common share attributable to common shareholders		
Basic		
As reported	$ 5.76	$ 6.70
Pro forma	$ 5.60	$ 6.63
Diluted		
As reported	$ 5.56	$ 6.50
Pro forma	$ 5.41	$ 6.43

The pro forma amounts shown above do not include the compensation costs associated with stock options granted prior to January 1, 2000.

The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions:

	2001	2000
Fair value of options granted (per share)		
Directors, officers and executives	$ 16.52	$ 16.35
Other employees	$ 13.56	$ 14.00
Risk-free interest rate	5.20%	6.18%
Expected life (years)		
Directors, officers and executives	5.5	5.5
Other employees	3.6	3.6
Expected volatility	39%	38%
Expected dividend yield	0.98%	–%

10 NET EARNINGS AND CASH FLOW FROM OPERATIONS PER COMMON SHARE

The following table provides a reconciliation between basic and diluted per share amounts:

	2001 (thousands)	2000 (thousands)	1999 (thousands)
Weighted average shares outstanding	121,300	116,701	103,906
Effect of dilutive stock options and warrants	2,594	2,624	1,739
Assumed settlement of preferred securities with common shares	2,678	1,407	–
Weighted average diluted shares outstanding	126,572	120,732	105,645

(millions of Canadian dollars, except per share amounts)	2001	2000	1999
Net earnings attributable to common shareholders	$ 698.2	$ 782.2	$ 200.2
Dividend on preferred securities (net of tax)	5.9	2.8	–
Diluted net earnings attributable to common shareholders	$ 704.1	$ 785.0	$ 200.2
Net earnings per common share attributable to common shareholders			
Basic	$ 5.76	$ 6.70	$ 1.93
Diluted	$ 5.56	$ 6.50	$ 1.90

(millions of Canadian dollars, except per share amounts)	2001	2000	1999
Cash flow from operations attributable to common shareholders	$ 1,920.0	$ 1,883.6	$ 723.5
Dividend on preferred securities	10.3	5.0	–
Diluted cash flow from operations attributable to common shareholders	$ 1,930.3	$ 1,888.6	$ 723.5
Cash flow from operations per common share attributable to common shareholders			
Basic	$ 15.83	$ 16.14	$ 6.96
Diluted	$ 15.25	$ 15.64	$ 6.85

For the year ended December 31, 2001, 692,790 stock options with a weighted average exercise price of $45.78 (2000 – 1,861,475 stock options with a weighted average exercise price of $44.38; 1999 – 3,279,010 stock options with a weighted average exercise price of $34.11 and 500,000 warrants with an exercise price of $30.00) were excluded from the calculation as their effect on per share amounts was antidilutive.

11 FINANCIAL INSTRUMENTS

Financial contracts

The Company's financial instruments recognized in the consolidated balance sheet consist of cash, accounts receivable, current liabilities and long-term debt.

The estimated fair values of financial instruments have been determined based on the Company's assessment of available market information and appropriate valuation methodologies; however, these estimates may not be necessarily indicative of the amounts that could be realized or settled in a current market transaction.

The carrying value of cash, accounts receivable, accounts payable, accrued liabilities and long-term debt with variable interest rates approximate their fair value.

The estimated fair values of other financial instruments are as follows:

	2001		2000	
	Carrying value	Fair value	Carrying value	Fair value
Asset (Liability)				
Fixed rate notes	$ (1,328.6)	$ (1,336.9)	$ (687.8)	$ (693.6)
Derivative financial instruments	$ –	$ (32.9)	$ –	$ (238.9)

The Company uses certain derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for trading or other speculative purposes. The following summarizes transactions outstanding at February 26, 2002:

	Term	Volume	Price	Index
Oil				
Oil price collars	Jan. 2002 – Mar. 2002	65,000 bbls/day	US $19.10 – US $22.28	WTI
	Apr. 2002 – Jun. 2002	31,000 bbls/day	US $19.52 – US $23.37	WTI
	Apr. 2002 – Jun. 2002	18,500 bbls/day	US $20.00 – US $23.33	WTI[1]
	Apr. 2002 – Dec. 2002	15,000 bbls/day	US $19.00 – US $21.77	WTI
	Jan. 2002 – Dec. 2002	35,500 bbls/day	US $20.55 – US $26.00	WTI
Brent differential swaps	Jan. 2002 – Dec. 2002	15,000 bbls/day	US $1.38	Dated Brent/WTI

[1] *Financial derivative was entered into subsequent to December 31, 2001.*

	Term	Volume	Price	Index
Natural Gas				
Empress – NYMEX differential swaps	Jan. 2002 – Oct. 2006	5,500 mmbtu/day	US $0.73	Empress/ NYMEX
NYMEX swaps	Jan. 2002 – Oct. 2006	10,000 mmbtu/day	Cdn $2.66	NYMEX
Sumas fixed	Jan. 2002 – Oct. 2003	20,000 mmbtu/day	Cdn $2.85	Sumas
AECO collars	Jan. 2002 – Mar. 2002	190,000 GJ/day	Cdn $3.67 – Cdn $4.58	AECO
	Apr. 2002 – Jun. 2002	130,000 GJ/day	Cdn $3.69 – Cdn $4.48	AECO
	Jan. 2002 – Jun. 2002	100,000 GJ/day	Cdn $3.23 – Cdn $4.00	AECO

	Term	Amount *($ millions)*	Average exchange rate *(US $/Cdn $)*
Foreign Currency			
Currency fixed	Jan. 2002 – Oct. 2002	US $0.4/month	1.37
Currency collars	Jan. 2002 – May 2003	US $4.2/month	1.43 – 1.53
	Jan. 2002 – Aug. 2004	US $25.0/month	1.51 – 1.59

	Term	Amount *($ millions)*	Fixed rate	Floating rate
Interest Rate				
Swaps – fixed to floating	Jan. 2002 – Jul. 2004	US $200	6.70%	LIBOR + 2.09%
	Jan. 2002 – Jul. 2006	US $200	6.70%	LIBOR + 1.58%
	Jan. 2002 – Jan. 2005	US $100	7.20%	LIBOR + 3.04%[1]
	Feb. 2002 – Jan. 2005	US $100	7.20%	LIBOR + 2.96%[1]
	Jan. 2002 – Jan. 2007	US $100	7.20%	LIBOR + 2.23%[1]
	Feb. 2002 – Jan. 2007	US $100	7.20%	LIBOR + 2.22%[1]

[1] *Financial derivative was entered into subsequent to December 31, 2001.*

Credit risk

Accounts receivable are mainly with customers in the oil and natural gas industry and are subject to normal industry credit risks. The Company minimizes these risks by entering into sales contracts with only highly rated entities. The Company is also exposed to certain losses in the event of non-performance by counterparties to derivative instruments; however, the Company minimizes this credit risk by entering into agreements with only highly rated financial institutions.

12 CORPORATE ACQUISITION

In July 2000, the Company issued 7,602,068 common shares at $47.10 per share and paid cash of $722.8 million to acquire all of the issued and outstanding common shares of Ranger Oil Limited ("Ranger"), a company engaged in the exploration for and development of petroleum and natural gas in the North Sea, North America and offshore West Africa. The acquisition was accounted for by the purchase method. The Company's consolidated statements of earnings, retained earnings and cash flows include operating results of Ranger since the date of acquisition. The purchase price was allocated to net assets acquired based on their estimated fair values.

	Amount
Property, plant and equipment	$ 1,966.4
Future site restoration	(129.3)
Future income tax	(149.8)
Net assets acquired	$ 1,687.3
Equity consideration	$ 358.0
Cash consideration	722.8
Assumption of net debt	376.6
Assumption of preferred securities	118.3
Assumption of non-cash working capital	111.6
Purchase price	$ 1,687.3

13 COMMITMENTS

The Company has committed to certain payments over the next five years as follows:

	2002	2003	2004	2005	2006
Natural gas transportation charges	$ 170.7	$ 153.0	$ 141.0	$ 130.6	$ 112.6
Oil transportation and pipeline charges	$ 20.8	$ 18.0	$ 19.7	$ 15.8	$ 14.3
Offshore equipment operating lease charges	$ 52.8	$ 42.0	$ 33.1	$ 30.0	$ 12.6
Electricity charges	$ 19.0	$ 17.5	$ 7.2	$ 7.2	$ 0.5
Office lease charges	$ 13.5	$ 12.9	$ 11.7	$ 11.2	$ 11.2

14 SEGMENTED INFORMATION

The Company's activities are conducted in three geographic segments: North America, the North Sea and offshore West Africa. All activities relate to the exploration, development, production and marketing of crude oil, natural gas liquids and natural gas.

	North America		
	2001	2000	1999
Revenue			
Oil and natural gas	$ 2,996.8	$ 2,905.1	$ 1,286.8
Less: royalties	(551.3)	(491.1)	(187.9)
	2,445.5	2,414.0	1,098.9
Expenses			
Production	580.2	462.6	252.0
Depletion, depreciation and amortization	750.9	587.7	384.3
Administration	37.1	26.4	17.0
Interest	129.7	155.5	90.1
Foreign exchange loss (gain)	7.9	0.8	2.6
Loss on sale of United States assets	24.1	–	–
	1,529.9	1,233.0	746.0
Earnings Before Taxes	915.6	1,181.0	352.9
Taxes other than income tax	8.5	12.3	8.1
Current income tax	15.1	14.7	7.8
Future income tax	295.7	478.6	136.8
Net Earnings	596.3	675.4	200.2
Dividend on preferred securities (net of tax)	(5.9)	(2.8)	–
Net Earnings Attributable to Common Shareholders	$ 590.4	$ 672.6	$ 200.2
Capital Expenditures[1]	$ 1,773.2	$ 965.2	$ 1,900.6
Segmented Assets	$ 7,654.0	$ 6,662.8	$ 4,850.8

[1] *North American capital asset expenditures for 2001 include a $190.4 million future tax addition (2000 – $76.6 million future tax recovery) on the purchase and sale of assets with a tax basis that differs from the purchase and sale price.*

North Sea			Offshore West Africa			Total		
2001	2000	1999	2001	2000	1999	2001	2000	1999
$ 523.0	$ 282.8	$ –	$ 41.6	$ 34.6	$ –	$ 3,561.4	$ 3,222.5	$ 1,286.8
(27.8)	(15.1)	–	(1.2)	–	–	(580.3)	(506.2)	(187.9)
495.2	267.7	–	40.4	34.6	–	2,981.1	2,716.3	1,098.9
123.3	54.9	–	27.0	15.4	–	730.5	532.9	252.0
129.0	54.4	–	23.9	2.5	–	903.8	644.6	384.3
0.5	0.8	–	–	–	–	37.6	27.2	17.0
8.3	6.8	–	(0.2)	–	–	137.8	162.3	90.1
5.3	3.2	–	1.5	(1.6)	–	14.7	2.4	2.6
–	–	–	–	–	–	24.1	–	–
266.4	120.1	–	52.2	16.3	–	1,848.5	1,369.4	746.0
228.8	147.6	–	(11.8)	18.3	–	1,132.6	1,346.9	352.9
59.1	33.3	–	1.5	3.9	–	69.1	49.5	8.1
61.8	33.7	–	–	–	–	76.9	48.4	7.8
(9.0)	(15.0)	–	(4.2)	0.4	–	282.5	464.0	136.8
116.9	95.6	–	(9.1)	14.0	–	704.1	785.0	200.2
–	–	–	–	–	–	(5.9)	(2.8)	–
$ 116.9	$ 95.6	$ –	$ (9.1)	$ 14.0	$ –	$ 698.2	$ 782.2	$ 200.2
$ 97.8	$ 54.9	$ –	$ 203.9	$ 39.3	$ –	$ 2,074.9	$ 1,059.4	$ 1,900.6
$ 953.5	$ 878.3	$ –	$ 433.2	$ 234.5	$ –	$ 9,040.7	$ 7,775.6	$ 4,850.8

15 DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Company's consolidated financial statements have been prepared in accordance with generally accepted accounting principles in Canada ("Canadian GAAP"). These principles conform in all material respects to those in the United States ("US GAAP") except for those noted below. Differences arising from US GAAP disclosure requirements have not been addressed in this document.

The application of US GAAP would have the following effects on consolidated net earnings as reported:

(millions of Canadian dollars)	Notes	2001	2000	1999
Net earnings – Canadian GAAP		$ 704.1	$ 785.0	$ 200.2
Adjustments (net of tax)				
Depletion	(C)	5.1	5.1	(6.2)
Deferred unrealized foreign exchange loss	(B,E)	(55.5)	(15.2)	19.3
Derivative financial instruments	(D)	60.9	(6.4)	20.9
Dividend on preferred securities	(E)	(5.9)	(2.8)	–
Deferred income taxes	(A)	–	–	(14.0)
Net earnings – US GAAP		$ 708.7	$ 765.7	$ 220.2
Per common share *(Canadian dollars)*				
Basic		$ 5.84	$ 6.56	$ 2.12
Diluted		$ 5.65	$ 6.37	$ 2.08

Comprehensive income under US GAAP would be as follows:

(millions of Canadian dollars)	Notes	2001	2000	1999
Net earnings – US GAAP		$ 708.7	$ 765.7	$ 220.2
Adoption of SFAS 133	(D)	(124.5)	–	–
Amortization of SFAS 133 adjustment	(D)	54.1	–	–
Foreign currency translation adjustment	(F)	72.8	–	–
Comprehensive income		$ 711.1	$ 765.7	$ 220.2

The application of US GAAP would have the following effects on the balance sheet as reported:

		2001		
(millions of Canadian dollars)	Notes	Canadian GAAP	Increase (decrease)	US GAAP
Property, plant and equipment	(C)	$ 8,442.9	$ (76.5)	$ 8,366.4
Deferred unrealized foreign exchange loss	(B)	$ 61.9	$ (61.9)	$ –
Derivative financial instruments	(D)	$ –	$ 32.2	$ 32.2
Deferred income taxes	(A)	$ 1,779.2	$ (27.7)	$ 1,751.5
Long-term debt	(E)	$ 2,669.2	$ 127.4	$ 2,796.6
Shareholders' equity		$ 3,868.9	$ (270.3)	$ 3,598.6

		2000		
(millions of Canadian dollars)	Notes	Canadian GAAP	Increase (decrease)	US GAAP
Property, plant and equipment	(C)	$ 7,141.5	$ (85.4)	$ 7,056.1
Deferred unrealized foreign exchange loss	(B)	$ 13.8	$ (13.8)	$ –
Derivative financial instruments	(D)	$ –	$ 22.4	$ 22.4
Deferred income taxes	(A)	$ 1,244.4	$ (31.2)	$ 1,213.2
Long-term debt	(E)	$ 2,454.5	$ 120.0	$ 2,574.5
Shareholders' equity		$ 3,216.9	$ (210.4)	$ 3,006.5

Notes:

A. Effective January 1, 2000, the Company adopted the liability method of accounting for income taxes for Canadian GAAP purposes. The new standard was adopted retroactively without restating prior periods. This standard is substantially similar to the accounting standard for income taxes under US GAAP; therefore, there are no material GAAP differences since the date of adoption.

B. The Company has deferred unrealized gains and losses on translation of long-term debt denominated in foreign currencies and is amortizing them over the remaining term of the debt. Under US GAAP, gains or losses on the translation of long-term debt are recorded in earnings as they occur.

C. Using Canadian full cost accounting rules, costs capitalized in each cost centre, net of future income taxes and future site restoration costs, are limited to an amount equal to the undiscounted, unescalated future net revenues from proved reserves plus the lower of cost or estimated fair market value of unproved properties ("the ceiling test"). Under the full cost method of accounting as set forth by the US Securities and Exchange Commission ("SEC"), the ceiling test differs from Canadian GAAP in that future net revenues from proved reserves are discounted at 10%.

D. The Company uses certain derivative financial instruments to manage its commodity price and foreign currency exposure in relation to future firmly committed and anticipated sales transactions. The Company has also used interest rate swaps to manage its interest rate exposure. Under Canadian GAAP these derivative financial instruments qualify, and are accounted for, as hedges of these transactions.

Effective January 1, 2001, the Company adopted Statement of Financial Accounting Standard ("SFAS") 133 "Accounting for Derivative Instruments and Hedging Activities" and SFAS 138 "Accounting for Certain Derivative Instruments and Certain Hedging Activities" to account for its commodity price and interest rate swap derivative financial instruments under US GAAP. Under SFAS 133, all derivative financial instruments are recognized on the balance sheet at their fair value. Changes in the fair value of derivative financial instruments are recognized in earnings unless specific criteria for hedging are met. At December 31, 2001, none of the outstanding derivative financial instruments had been designated as hedges for US GAAP purposes.

Adoption of SFAS 133 resulted in the Company recognizing a derivative financial instruments liability of $183.4 million and a charge to comprehensive income of $124.5 million, net of future income tax recoveries of $58.9 million. Of the initial liability recognized on January 1, 2001, a loss of $54.1 million, net of future income tax recoveries of $25.6 million, was reclassified to net earnings during the year. It is estimated that for 2002, a loss of $31.0 million, net of future income tax recoveries of $14.7 million, will be reclassified to net earnings.

Under US GAAP, foreign currency swap contracts used to hedge foreign currency exposure to anticipated, but not firmly committed, transactions cannot be accounted for as hedges under SFAS 52 "Foreign Currency Translation". Accordingly, for US GAAP reporting, gains and losses from changes in the fair market value of foreign currency swap contracts related to these anticipated transactions are recognized in income when those changes in market value occur.

E. Under Canadian GAAP, the preferred securities are considered to be equity because the Company has the unrestricted right to pay dividends, principal and principal prepayments with common shares. Under US GAAP, the Company's preferred securities would be classified as debt rather than as equity. Accordingly, the dividend on the preferred securities would be classified as an expense rather than a dividend.

F. Under US GAAP, exchange gains and losses arising from the translation of self-sustaining foreign operations are included in comprehensive income.

G. The Company has included transportation costs of $84.2 million, $67.8 million and $46.1 million in oil and natural gas revenues for the years ended December 31, 2001, 2000 and 1999, respectively.

H. Recently Issued Accounting Standards

Foreign exchange

Effective January 1, 2002, the Company adopted the Canadian Institute of Chartered Accountants' ("CICA") amendments to CICA 1650 "Foreign Currency Translation". The amended standard no longer allows for the deferral and amortization of foreign exchange gains and losses on foreign denominated long-term monetary assets and liabilities over the life of the asset or liability. As a result, all foreign exchange gains and losses must flow through earnings in the year in which they occur. This results in similar accounting treatment as current US GAAP. The changes will be adopted retroactively and prior year comparatives will be restated.

Hedging

In December 2001, the CICA issued Accounting Guideline 13 "Hedging Relationships". The guideline establishes conditions for when hedge accounting may be applied, but does not establish accounting treatment for hedges.

Callable debt obligations

In October 2001, the CICA Emerging Issues Committee ("EIC") issued EIC 122 "Callable Debt Obligations" to clarify the balance sheet classification of callable debt obligations as current or long-term. Application of this EIC did not result in the reclassification of any of the Company's debt to current from long-term.

Business Combinations and Goodwill

During 2001, the CICA issued CICA 1581 "Business Combinations" and CICA 3062 "Goodwill and Other Intangible Assets" and the Financial Accounting Standards Board ("FASB") issued SFAS 141 "Business Combinations" and SFAS 142 "Goodwill and Other Intangible Assets". The CICA and FASB accounting standards are substantially the same. Under the new standards, all business combinations initiated after June 30, 2001, must be accounted for by the purchase method, which may result in the recognition of goodwill. Goodwill and other intangible assets with indefinite lives will no longer be amortized but will be subject to periodic impairment tests. Adoption of these new standards is prospective and has no impact on the Company's financial statements as at December 31, 2001.

Accounting for Asset Retirement Obligations

In June 2001, FASB issued SFAS 143 "Accounting for Asset Retirement Obligations". SFAS 143 requires recognition of the fair value of the retirement obligation for long-lived tangible assets as a liability on the Company's balance sheet. Retirement cost equal to the retirement liability is to be capitalized as part of the cost of the related capital asset and amortized to expense over the life of the asset. This new standard is effective for fiscal years beginning on or after June 25, 2002. Adoption of this standard will result in an increase in property, plant and equipment and future site restoration on the Company's balance sheet but is not expected to have a material impact on earnings.

Accounting for the Impairment or Disposal of Long-Lived Assets

In August 2001, FASB issued SFAS 144 "Accounting for the Impairment or Disposal of Long-Lived Assets". This standard supercedes SFAS 121 "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of" and Accounting Principles Board Opinion 30 "Reporting Results of Operations – Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions". The standard requires that an impairment be recognized on long-lived assets when the expected undiscounted cash flows are less than the carrying amount. The standard also addresses long-lived assets to be disposed of and discontinued operations. Adoption of this standard is not expected to have a material impact on the Company's financial statements.

SUPPLEMENTARY OIL AND NATURAL GAS INFORMATION (UNAUDITED)

This supplementary oil and natural gas information is provided in accordance with the United States SFAS 69 "Disclosures about Oil and Gas Producing Activities".

Net Proved Oil and Natural Gas Reserves

The Company retains independent petroleum engineering consultants to evaluate the majority of the Company's proved oil and natural gas reserves, with the remainder evaluated by the Company's internal petroleum engineers.

- For the year ended December 31, 2001, the reports by Sproule Associates Limited ("Sproule") covered 91% of the Company's reserves.
- For the year ended December 31, 2000, reports by Sproule (Canadian assets), Ryder Scott Company (US assets) and AEA Technology (international assets) covered 98% of the Company's reserves.
- For the year ended December 31, 1999, the report by Sproule covered 97% of the Company's reserves.

Proved oil and natural gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are reserves that can be expected to be recovered from existing wells with existing equipment and operating methods.

Estimates of oil and natural gas reserves are subject to uncertainty and will change as additional information regarding producing fields and technology becomes available and as future economic and operating conditions change.

The following table summarizes the Company's proved and proved developed oil and natural gas reserves, net of royalties, as at December 31, 2001, 2000, and 1999:

Oil and Natural Gas Liquids

(mmbbls)	North America	North Sea	Offshore West Africa	Total
Net proved reserves				
Reserves, December 31, 1998	251	–	–	251
Extensions, discoveries	24	–	–	24
Purchases of reserves in place	237	–	–	237
Sales of reserves in place	–	–	–	–
Production	(28)	–	–	(28)
Revisions of previous estimates	17	–	–	17
Reserves, December 31, 1999	501	–	–	501
Extensions, discoveries	59	–	–	59
Purchases of reserves in place	68	97	30	195
Sales of reserves in place	(13)	–	–	(13)
Production	(51)	(6)	(1)	(58)
Revisions of previous estimates	4	2	1	7
Reserves, December 31, 2000	568	93	30	691
Extensions, discoveries	13	–	37	50
Purchases of reserves in place	14	–	8	22
Sales of reserves in place	(1)	–	–	(1)
Production	(54)	(13)	(1)	(68)
Revisions of previous estimates	43	(2)	(14)	27
Reserves, December 31, 2001	583	78	60	721
Net proved developed reserves:				
December 31, 1998	150	–	–	150
December 31, 1999	299	–	–	299
December 31, 2000	328	61	2	391
December 31, 2001	344	51	20	415

Natural Gas

(bcf)	North America	North Sea	Offshore West Africa	Total
Net proved reserves				
Reserves, December 31, 1998	1,553	–	–	1,553
Extensions, discoveries	210	–	–	210
Purchases of reserves in place	248	–	–	248
Sales of reserves in place	(16)	–	–	(16)
Production	(217)	–	–	(217)
Revisions of previous estimates	(7)	–	–	(7)
Reserves, December 31, 1999	1,771	–	–	1,771
Extensions, discoveries	201	–	–	201
Purchases of reserves in place	214	89	52	355
Sales of reserves in place	(33)	–	–	(33)
Production	(226)	(1)	–	(227)
Revisions of previous estimates	(32)	3	1	(28)
Reserves, December 31, 2000	1,895	91	53	2,039
Extensions, discoveries	379	–	–	379
Purchases of reserves in place	134	–	23	157
Sales of reserves in place	(20)	–	–	(20)
Production	(255)	(4)	–	(259)
Revisions of previous estimates	(69)	7	(9)	(71)
Reserves, December 31, 2001	2,064	94	67	2,225
Net proved developed reserves:				
December 31, 1998	1,261	–	–	1,261
December 31, 1999	1,466	–	–	1,466
December 31, 2000	1,569	32	–	1,601
December 31, 2001	1,845	19	16	1,880

Capitalized Costs Related to Oil and Natural Gas Activities

	2001			
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
Proved properties	$ 9,194.3	$ 990.7	$ 376.8	$ 10,561.8
Unproved properties	584.6	59.6	48.4	692.6
	9,778.9	1,050.3	425.2	11,254.4
Less: accumulated depletion and depreciation	(2,704.4)	(184.7)	(15.3)	(2,904.4)
Net capitalized costs	$ 7,074.5	$ 865.6	$ 409.9	$ 8,350.0

	2000			
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
Proved properties	$ 7,517.3	$ 822.8	$ 206.5	$ 8,546.6
Unproved properties	493.3	45.5	14.8	553.6
	8,010.6	868.3	221.3	9,100.2
Less: accumulated depletion and depreciation	(2,004.2)	(52.3)	(0.9)	(2,057.4)
Net capitalized costs	$ 6,006.4	$ 816.0	$ 220.4	$ 7,042.8

	1999			
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
Proved properties	$ 5,456.7	$ –	$ –	$ 5,456.7
Unproved properties	437.0	–	–	437.0
	5,893.7	–	–	5,893.7
Less: accumulated depletion and depreciation	(1,444.1)	–	–	(1,444.1)
Net capitalized costs	$ 4,449.6	$ –	$ –	$ 4,449.6

Costs Incurred in Oil and Natural Gas Activities

(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
	2001			
Property acquisitions				
Proved	$ 647.2	$ –	$ 62.4	$ 709.6
Unproved	73.0	4.5	–	77.5
Exploration	60.9	24.7	63.7	149.3
Development	986.0	68.3	77.8	1,132.1
	$ 1,767.1	$ 97.5	$ 203.9	$ 2,068.5

(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
	2000			
Property acquisitions				
Proved	$ 649.6	$ 768.2	$ 182.0	$ 1,599.8
Unproved	168.2	45.3	–	213.5
Exploration	47.9	2.7	15.9	66.5
Development	785.4	52.1	23.4	860.9
	$ 1,651.1	$ 868.3	$ 221.3	$ 2,740.7

(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
	1999			
Property acquisitions				
Proved	$ 1,255.4	$ –	$ –	$ 1,255.4
Unproved	192.7	–	–	192.7
Exploration	35.9	–	–	35.9
Development	413.9	–	–	413.9
	$ 1,897.9	$ –	$ –	$ 1,897.9

Results of Operations from Oil and Natural Gas Producing Activities

Canadian Natural's results of operations from oil and natural gas producing activities for 2001, 2000, and 1999 are summarized in the following table:

(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
	2001			
Oil and natural gas revenue (net of royalties)	$ 2,437.8	$ 495.1	$ 40.4	$ 2,973.3
Production expenses	580.2	123.3	27.0	730.5
Depletion, depreciation and amortization	741.2	129.0	23.9	894.1
Tax expense	358.4	[illegible]	(2.7)	469.9
Results of operations	758.0	$ 128.6	$ (7.8)	$ 878.8

(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
	2000			
Oil and natural gas revenue (net of royalties)	$ 2,411.2	$ 267.7	$ 34.6	$ 2,713.5
Production expenses	462.6	54.9	15.4	532.9
Depletion, depreciation and amortization	579.2	54.4	2.5	636.1
Tax expense	459.9	70.8	4.3	535.0
Results of operations	$ 909.5	$ 87.6	$ 12.4	$ 1,009.5

(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
	1999			
Oil and natural gas revenue (net of royalties)	$ 1,119.5	$ -	$ -	$ 1,119.5
Production expenses	252.0	-	-	252.0
Depletion, depreciation and amortization	388.6	-	-	388.6
Tax expense	160.8	-	-	160.8
Results of operations	$ 318.1	$ -	$ -	$ 318.1

Standardized Measure of Discounted Future Net Cash Flows from Proved Oil and Natural Gas Reserves and Changes Therein

The following standardized measure of discounted future net cash flows from proved oil and natural gas reserves has been computed using year-end prices and costs and year-end statutory income tax rates. A mid-year discount factor of 10% has been applied in determining the standardized measure of discounted future net cash flows.

The Company does not believe that the standardized measure of discounted future net cash flows will be representative of actual future net cash flows and should not be considered to represent the fair value of the oil and natural gas properties. Actual net cash flows will differ from the presented estimated future net cash flows in that:

- Future production will include production not only from proved properties, but may also include production from probable and potential reserves;
- Future production of oil and natural gas from proved properties will differ from reserves estimated;
- Future production rates will vary from those estimated;
- Future rather than year-end prices and costs will apply;
- Economic factors such as interest rates, regulatory and fiscal environments and operating conditions will change;
- Future estimated income taxes do not take into account the effects of future exploration expenditures; and
- Future estimated petroleum revenue tax, which takes into account the effects of certain future development expenditures, will differ from that estimated.

Future net revenues, development, production and restoration costs have been based upon the estimates referred to above.

The following tables summarize the Company's future net cash flows relating to proved oil and natural gas reserves based on the standardized measure as prescribed in SFAS 69:

	2001			
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore West Africa**	**Total**
Future cash inflows	$ 19,206.9	$ 3,089.0	$ 1,738.4	$ 24,034.3
Future production costs	(6,587.4)	(1,367.8)	(575.6)	(8,530.8)
Future development and restoration costs	(1,203.8)	(354.3)	(555.5)	(2,113.6)
Future taxes	(2,781.8)	(548.5)	(136.1)	(3,466.4)
Future net cash flows	8,633.9	818.4	471.2	9,923.5
10% annual discount for timing of future cash flows	(3,387.8)	(241.4)	(148.5)	(3,777.7)
Standardized measure of future net cash flows	$ 5,246.1	$ 577.0	$ 322.7	$ 6,145.8

	2000			
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore West Africa**	**Total**
Future cash inflows	$ 33,126.7	$ 3,999.2	$ 1,209.9	$ 38,335.8
Future production costs	(5,997.7)	(1,701.7)	(376.5)	(8,075.9)
Future development and restoration costs	(1,269.9)	(426.9)	(179.4)	(1,876.2)
Future taxes	(8,039.7)	(766.1)	(232.4)	(9,038.2)
Future net cash flows	17,819.4	1,104.5	421.6	19,345.5
10% annual discount for timing of future cash flows	(6,988.7)	(366.2)	(111.5)	(7,466.4)
Standardized measure of future net cash flows	$ 10,830.7	$ 738.3	$ 310.1	$ 11,879.1

	1999			
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore West Africa**	**Total**
Future cash inflows	$ 18,271.0	$ –	$ –	$ 18,271.0
Future production costs	(3,668.7)	–	–	(3,668.7)
Future development and restoration costs	(840.8)	–	–	(840.8)
Future taxes	(3,860.8)	–	–	(3,860.8)
Future net cash flows	9,900.7	–	–	9,900.7
10% annual discount for timing of future cash flows	(4,071.8)	–	–	(4,071.8)
Standardized measure of future net cash flows	$ 5,828.9	$ –	$ –	$ 5,828.9

The principal sources of change in the standardized measure of discounted future net cash flows are summarized in the following table:

(millions of Canadian dollars)	2001	**2000**	**1999**
Sales of oil and natural gas produced (net of production costs)	$ (1,393.6)	$ (1,328.0)	$ (496.5)
Net changes in prices and production costs	(9,132.3)	5,615.7	1,955.1
Extensions, discoveries and improved recovery	1,069.0	1,740.0	552.2
Changes in estimated future development costs	(166.3)	(678.2)	(159.1)
Purchases of reserves in place	430.9	4,078.0	3,425.1
Sales of reserves in place	(34.2)	(319.4)	(19.1)
Revisions of previous estimates	63.6	(84.7)	217.1
Accretion of discount	1,744.8	810.2	219.2
Timing and other	(1,729.4)	(560.4)	221.0
Net change in income taxes	3,414.2	(3,223.0)	(1,894.7)
Net change	(5,733.3)	6,050.2	4,020.3
Balance – beginning of year	11,879.1	5,828.9	1,808.6
Balance – end of year	$ 6,145.8	$ 11,879.1	$ 5,828.9

ten-year review

Years ended December 31	2001	2000	1999
FINANCIAL			
($ millions, except per share data)			
Revenue *(net of royalties)*	2,981.1	2,716.3	1,098.9
Expenses	1,848.5	1,369.4	746.0
Taxes	428.5	561.9	152.7
Cash flow from operations attributable to common shareholders	1,920.0	1,883.6	723.5
Per share*	15.83	16.14	6.96
Net earnings attributable to common shareholders	698.2	782.2	200.2
Per share*	5.76	6.70	1.93
Balance sheet information			
Net capital expenditures	1,884.5	2,823.3	1,900.6
Working capital (deficiency) surplus	(5.6)	(77.3)	36.4
Total assets	9,040.7	7,775.6	4,850.8
Long-term debt	2,669.2	2,454.5	2,156.8
Shareholders' equity	3,868.9	3,216.9	1,892.0
Common shares outstanding *(millions)*	121.2	122.3	111.5
Weighted average shares outstanding *(millions)*	121.3	116.7	103.9
Number of employees *(December 31)*	1,186	943	675
OPERATING			
Reserves (proved and probable)			
Crude oil and NGLs *(mmbbls)*			
Proved			
North America	644	642	554
North Sea	85	102	–
Offshore West Africa	61	37	–
Probable			
North America	95	88	86
North Sea	23	33	–
Offshore West Africa	51	9	–
	959	911	640
Natural gas *(bcf)*			
Proved			
North America	2,566	2,360	2,183
North Sea	94	91	–
Offshore West Africa	69	66	–
Probable			
North America	349	402	364
North Sea	24	23	–
Offshore West Africa	27	19	–
	3,129	2,961	2,547
DAILY PRODUCTION			
Crude oil and NGLs *(mbbls)*			
North America	167	155	87
North Sea	36	17	–
Offshore West Africa	3	2	–
	206	174	87
Natural gas *(mmcf)*			
North America	906	793	721
North Sea	12	1	–
	918	794	721
Average crude oil and NGLs price *($/bbl)*	24.31	29.99	21.04
Average natural gas price *($/mcf)*	5.16	4.53	2.36
Core undeveloped land holdings *(millions of acres)*			
Gross	10.6	11.5	6.2
Net	7.8	8.0	4.8
Drilling activity *(net wells)*			
Crude oil wells	231	333	211
Natural gas wells	476	408	458
Injection/stratigraphic	353	38	9
Dry and abandoned	32	34	49
	1,092	813	727
Success rate (%)	97%	96%	93%

**Restated to reflect two for one stock split in June 1993.*

	1998	1997	1996	1995	1994	1993	1992
	760.8	768.7	532.3	245.4	221.2	135.5	66.2
	635.9	552.5	346.7	171.5	123.6	75.4	42.5
	65.9	105.0	90.6	31.5	43.4	25.8	9.8
	444.2	503.0	359.7	153.6	152.8	94.2	41.8
	4.47	5.13	4.32	2.22	2.39	1.64	0.81
	59.0	111.3	95.0	42.4	54.2	34.3	13.9
	0.59	1.14	1.14	0.61	0.85	0.60	0.27
	609.7	1,119.2	1,203.6	238.8	331.2	271.2	90.0
	57.9	(18.6)	(0.8)	9.7	4.0	2.2	(2.0)
	3,247.4	2,931.1	2,062.6	900.4	737.8	436.9	173.2
	1,425.5	1,136.3	588.0	237.7	242.9	189.2	60.5
	1,277.4	1,204.3	1,074.2	496.3	356.2	171.2	81.5
	99.8	98.8	97.4	74.0	66.7	59.9	54.4
	99.3	98.0	83.2	69.3	63.9	57.6	51.5
	547	542	428	205	162	123	61
	287	270	141	53	43	29	14
	–	–	–	–	–	–	–
	–	–	–	–	–	–	–
	97	81	50	24	14	14	5
	–	–	–	–	–	–	–
	–	–	–	–	–	–	–
	384	351	191	77	57	43	19
	1,905	1,733	1,605	924	894	666	333
	–	–	–	–	–	–	–
	–	–	–	–	–	–	–
	311	363	362	208	175	101	25
	–	–	–	–	–	–	–
	–	–	–	–	–	–	–
	2,216	2,096	1,967	1,132	1,069	767	358
	76	71	37	17	13	8	4
	–	–	–	–	–	–	–
	–	–	–	–	–	–	–
	76	71	37	17	13	8	4
	673	626	499	305	238	165	94
	–	–	–	–	–	–	–
	673	626	499	305	238	165	94
	12.93	18.82	23.52	19.82	18.18	18.17	20.84
	2.12	1.91	1.71	1.43	1.99	1.72	1.31
	5.5	5.7	5.1	3.0	2.6	2.0	0.6
	4.8	4.9	4.2	2.4	2.0	1.3	0.5
	107	443	209	113	44	33	10
	193	200	128	74	138	68	20
	15	1	1	–	–	–	–
	43	67	63	22	44	28	21
	358	711	401	209	226	129	51
	88%	91%	84%	89%	80%	79%	58%

corporate information

Board of Directors

N. Murray Edwards[1][2][3]
President,
Edco Financial Holdings Ltd.
Calgary, Alberta

James T. Grenon[1][2]
Managing Director,
TOM Capital Associates Inc.
Calgary, Alberta

John G. Langille
President,
Canadian Natural Resources Limited
Calgary, Alberta

Keith A.J. MacPhail[3]
President & C.E.O.,
Bonavista Petroleum Ltd.
Calgary, Alberta

Allan P. Markin[1]
Chairman of the Board,
Canadian Natural Resources Limited
Calgary, Alberta

James S. Palmer, C.M., Q.C.[2][3]
Chairman,
Burnet, Duckworth & Palmer LLP
Calgary, Alberta

Eldon R. Smith, M.D.[3]
Professor and Former Dean,
Faculty of Medicine
The University of Calgary
Calgary, Alberta

(1) Member of the Compensation Committee
(2) Member of the Audit Committee
(3) Member of the Reserve Committee

Management Committee

Allan P. Markin
Chairman

John G. Langille
President

Brian L. Illing
Executive Vice-President, Exploration

Steve W. Laut
Executive Vice-President, Operations

Allen M. Knight
Senior Vice-President, International and Corporate Development

Tim S. McKay
Senior Vice-President, North American Operations

Réal M. Cusson
Vice-President, Marketing

Réal J.H. Doucet
Vice-President, Oil Sands

Douglas A. Proll
Vice-President, Finance

Lyle G. Stevens
Vice-President, Exploitation

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www.cnrl.com

Registrar and Transfer Agent

Computershare Trust Company of Canada
Calgary, Alberta
Toronto, Ontario

Auditors

PricewaterhouseCoopers LLP
Calgary, Alberta

Evaluation Engineers

Sproule Associates Limited
Calgary, Alberta

Stock Listing

The Toronto Stock Exchange
Symbol: CNQ

New York Stock Exchange
Symbol: CED

Notice of Annual Meeting

The annual meeting of shareholders will be held at 3:00 p.m. on Thursday, May 9, 2002, in the Ballroom of the Metropolitan Centre, Calgary, Alberta. All shareholders are invited to attend.

Company Definition

Throughout the annual report, Canadian Natural Resources Limited is referred to as "Canadian Natural" or the "Company".

Currency

All amounts are reported in Canadian currency unless otherwise stated.

Volume Reporting

All production, sales and reserve statistics are Canadian Natural's working interest amounts before deduction of royalties, unless stated otherwise. Where volumes are reported in barrels of oil equivalent ("boe"), natural gas is converted to oil at six thousand cubic feet per barrel unless otherwise noted. This conversion ratio approximates relative heating values.

Abbreviations

bbls = barrels
mbbls = thousand barrels
mmbbls = million barrels
mcf = thousand cubic feet
mmcf = million cubic feet
bcf = billion cubic feet
boe = barrels of oil equivalent

Forward-looking Statements

Certain information regarding the Company contained herein may constitute forward-looking statements under applicable securities laws. Such statements are subject to known or unknown risks and uncertainties that may cause actual results to differ materially from those anticipated in the forward-looking statements.

Common Share Dividend

Prior to 2001, dividends had not been paid on the common shares of Canadian Natural. On January 17, 2001, the Board of Directors approved a dividend policy for the payment of a regular quarterly dividend of $0.10 per common share commencing April 2001. This was subsequently increased 25% to $0.125 per common share effective April 2002. These dividends will be payable in January, April, July and October of each year. The dividend policy of the Company continues to be under periodic review by the Board of Directors and is subject to change at any time depending upon the earnings of the Company, its financial requirements and other factors existing at the time.

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defined

- owner operator
- core area focus
- balanced assets
- project inventory
- capital discipline
- team commitment
- environmental responsibility

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